

February 22, 2022

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 Nos. EL19-58-00_; ER19-1486-00_
Compliance Filing*

Dear Secretary Bose:

In compliance with the Federal Energy Regulatory Commission's ("Commission") December 22, 2021 Order on Remand¹ in the above-referenced proceedings, PJM Interconnection, L.L.C. ("PJM") hereby submits modifications to the PJM Open Access Transmission Tariff ("Tariff") and Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement")² to implement the reserve market enhancements the Commission initially accepted in the May 2020 Order,³ and affirmed in the Remand Order.⁴

PJM intends to implement the reserve market enhancements on October 1, 2022, as discussed in Section III below. This timeline will accommodate the necessary schedule for

¹ *PJM Interconnection, L.L.C.*, 177 FERC ¶ 61,209 (2021) ("Remand Order"), *order granting clarification*, 178 FERC ¶ 61,085 (2022).

² For the purpose of this filing, capitalized terms not defined herein shall have the meaning as contained in the Tariff and Operating Agreement. All references to the Operating Agreement, Schedule 1 herein shall also be meant to reference the identical provisions in Tariff, Attachment K-Appendix.

³ *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153 (2020) ("May 2020 Order").

⁴ Remand Order at P 2. The Remand Order also directed PJM to submit a compliance filing restoring the historical energy and ancillary services revenue offset ("EAS Offset") for use in PJM's capacity market, effective November 12, 2020. PJM has submitted those changes in a separate compliance filing in Docket No. EL19-58-011.

coding, software, market engine work, allow PJM to test its software, and resolve any other technical issues that may arise during the fall season. This approach is also consistent with PJM's policy to avoid implementing major market improvements during the summer months.

I. BACKGROUND

On December 22, 2021, the Commission, on voluntary remand from the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"),⁵ considered whether the Commission, in the May 2020 Order, erred in deeming PJM's Tariff and Operating Agreement unjust and unreasonable as they pertain to the PJM reserve market, and setting a replacement rate.

In the May 2020 Order, the Commission found PJM's reserves market unjust and unreasonable, for systematically failing to: (1) acquire through the market sufficient reserves necessary to maintain reliability in the PJM Region; (2) price reserve products at a level that reasonably reflects the marginal cost of procuring the necessary amount of reserves; and (3) "send appropriate price signals for efficient resource investment."⁶ The Commission "largely adopt[ed]" PJM's proposed changes to the reserve market as the replacement rate.⁷

⁵ *Am. Mun. Power, Inc. v. FERC*, No. 20-1372 (D.C. Cir. Aug. 23, 2021) (order granting unopposed motion for voluntary remand). The consolidated appeals involve challenges to *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153 (May 2020 Order), *order on reh'g*, 173 FERC ¶ 61,123 (2020) (November 2020 Rehearing Order); and *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 (2020) (November 2020 Compliance Order), *order on reh'g*, 174 FERC ¶ 61,180 (2021) (March 2021 Compliance Rehearing Order).

⁶ May 2020 Order at P 74.

⁷ May 2020 Order at P 2.

In the Remand Order, however, the Commission affirmed in part, and reversed in part, the determinations in the May 2020 Order. Specifically, the Commission affirmed that the bifurcation of Tier 1 and Tier 2 Synchronized Reserve products, misalignment of the day-ahead and real-time reserve markets, and the provisions regarding resources' reserve capability and offer rules are unjust and unreasonable.⁸ The Commission also reversed its prior determinations and found that the currently effective Reserve Penalty Factors and two-step Operating Reserve Demand Curves ("ORDCs") were not shown to be unjust and unreasonable.⁹ The Commission directed PJM to submit a compliance filing, within 60 days of the order, to resolve those issues.¹⁰ This compliance filing satisfies that requirement.

II. SATISFACTION OF THE COMPLIANCE REQUIREMENTS OF THE REMAND ORDER

A. PJM Is Revising the Currently Effective Market Rules to Implement the Reserve Market Enhancements Affirmed in the Remand Order.

1. Commission Directive

In the Remand Order, the Commission affirmed its findings regarding the unjustness and unreasonableness of PJM's separate treatment of Tier 1 and Tier 2 Synchronized Reserve products;¹¹ the current misalignment of the day-ahead and real-time reserve markets;¹² and various provisions related to resources' eligibility for reserves,

⁸ Remand Order at P 2.

⁹ *Id.*

¹⁰ *Id.*

¹¹ May 2020 Order at PP 84-85, 88-90, 115-121.

¹² *Id.* at PP 86, 254-256.

determining resources' reserve capability, and offer rules.¹³ However, because the Remand Order reversed the Commission's prior determinations with respect to updating the Reserve Penalty Factors and ORDCs, the Commission directed PJM to submit a compliance filing implementing the market rule revisions "previously accepted in this proceeding . . . [but] reflect[ing] the currently effective Reserve Penalty Factors and the ORDCs."¹⁴

2. *PJM Response*

To comply with this directive, PJM is updating the currently effective reserve market rules in Operating Agreement, Schedule 1 and Tariff, Attachment K-Appendix to include the reserve market enhancements accepted by the Commission in the May 2020 Order and affirmed in the Remand Order. Specifically, PJM generally is carrying over, without any change, the revisions accepted in the May 2020 Order (as updated in the July 6, 2020 compliance filing¹⁵) to Operating Agreement, Schedule 1, sections 1.5A, 1.7, 1.10, 1.11, and 3.2.

PJM is also carrying forward the energy market revisions accepted in sections 2.2, 2.5, and 2.6, but such revisions are not as straight forward given the intervening changes to these three sections as part of PJM's implementation of fast-start pricing. Specifically, the May 2020 Order accepted revisions updating the rules to allow Day-ahead Energy Market Locational Marginal Prices ("LMPs") to increase when PJM is unable to procure sufficient reserves to meet the minimum reserve requirements. But, because section 2.2 was overhauled as part of the fast-start proceeding, PJM is adding this revision as new

¹³ *Id.* at PP 271-278.

¹⁴ Remand Order at P 2.

¹⁵ Compliance Filing of PJM Interconnection, L.L.C., Docket No. EL19-58-002 (July, 6, 2020), *accepted by PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 (2020).

subsection 2.6(b), with the text generally unchanged from what PJM initially proposed to add in Operating Agreement, Schedule 1, section 2.2(d)(i).¹⁶ In addition, PJM is carrying forward revised language that clarifies that real-time and day-ahead energy market prices will be determined in conjunction with clearing the reserve markets and more explicitly spells out PJM's current approach.¹⁷

B. PJM's Tariff Reflects the Currently Effective Reserve Penalty Factor.

1. Commission Directive

In the Remand Order, the Commission directed PJM to revise its Tariff and Operating Agreement records previously accepted in the May 2020 Order to reflect the currently effective Reserve Penalty Factors. In addition, the Commission directed PJM to "include in its compliance filing Reserve Penalty Factors for 30-minute Reserve that are the same as the Reserve Penalty Factors for Synchronized Reserve and Primary Reserve."¹⁸

2. PJM Response

To comply with this directive, PJM is not revising the Reserve Penalty Factors stated in its currently effective market rules of \$850/MWh for the Synchronized Reserve Requirement and Primary Reserve Requirement and \$300/MWh the Extended Synchronized Reserve Requirement and Extended Primary Reserve Requirement.¹⁹ PJM is revising the Secondary Reserve market rules the Commission accepted in the May 2020

¹⁶ Compare initial 206 filing at Operating Agreement, Schedule 1, section 2.2(d)(i) with proposed Operating Agreement, Schedule 1, section 2.6(b).

¹⁷ See proposed Operating Agreement, Schedule 1, sections 2.5(a) (Calculation of Real-time Prices) and 2.6(a) (Calculation of Day-ahead Prices).

¹⁸ Remand Order at P 47 n.105.

¹⁹ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(d)(iii) (Synchronized Reserve) and 3.2.3.A.001(c)(iii) (Non-Synchronized Reserve).

Order and affirmed in the Remand Order to provide for Reserve Penalty Factors of \$850/MWh for the 30-minute Reserve Requirement and \$300/MWh the Extended 30-minute Reserve Requirement.²⁰

C. PJM's Tariff Reflects the Currently Effective ORDC.

1. Commission Directive

In the Remand Order, the Commission directed PJM to revise its Tariff and Operating Agreement records previously accepted in the May 2020 Order to reflect the currently effective ORDC.²¹ In addition, the Commission directed PJM to include in its compliance filing ORDCs for clearing Secondary Reserve and meeting the 30-minute Reserve Requirement based on the same Reserve Penalty Factors for Synchronized Reserve and Primary Reserve.²²

2. PJM Response

To comply with this directive, PJM is adding into its currently effective market rules the definition of the “Operating Reserve Demand Curve” to describe the two-step curve. While the two-step ORDC is not described in the currently effective market rules, implementation of the accepted reserve market enhancements necessitates defining the ORDCs. That is, new market rules for clearing the reserve markets and determining reserve markets clearing prices require use of a defined ORDC term. Retaining the two-stepped ORDCs does not affect the need to define the term.

²⁰ See proposed Operating Agreement, Schedule 1, sections 3.2.3A.01(d)(iii) (Secondary Reserve).

²¹ Remand Order at P 36.

²² Remand Order at P 47 n.105.

Accordingly, and consistent with the Remand Order, PJM is including revisions that define the ORDCs to include both the reserve requirement and the extended reserve requirement.²³ The ORDCs for clearing each reserve market will be formed using the reserve requirement and extended reserve requirement and Reserve Penalty Factors applicable to that product.²⁴ Thus, the ORDC to clear Secondary Reserve and meet the 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement will be two-stepped, based on a \$850/MWh Reserve Penalty Factor for the 30-minute Reserve Requirement and a \$300/MWh Reserve Penalty Factor for the Extended 30-minute Reserve Requirement.²⁵ The ORDCs for Synchronized Reserve and Non-Synchronized Reserve will be similarly formed. Given that PJM is not proposing to change the current-effective rules that the reserve requirements may be adjusted “to account for additional reserves scheduled to address operational uncertainty,”²⁶ the ORDCs “shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.”²⁷

D. PJM’s Tariff Carries Forward Reserve Market Price Capping and Applies Price Capping to the Secondary Reserve Market.

1. Commission Directive

On February 11, 2022, the Commission clarified that the reserve market enhancements affirmed in Remand Order did not include removal of price caps in the

²³ See proposed Operating Agreement, Schedule 1, section 3.2.3A.02.

²⁴ See proposed Operating Agreement, Schedule 1, section 3.2.3A.02.

²⁵ See proposed Operating Agreement, Schedule 1, section 3.2.3A.01(d)(iii).

²⁶ See proposed Operating Agreement, Definitions, 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; Primary Reserve Requirement and Extended Primary Reserve Requirement; and Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement.

²⁷ See proposed Operating Agreement, Schedule 1, section 3.2.3A.02.

reserve markets.²⁸ However, the Commission stated that because the Remand Order affirmed “adopt[ion of] a new 30-minute Reserve Requirement and Secondary Reserve product, PJM may propose revised reserve price caps to reflect the addition of this new product.”²⁹ Accordingly, PJM’s obligation in this compliance filing is to implement the reserve market enhancements affirmed by the Remand Order, consistent with the reserve price cap approach in the currently effective reserve market rules.

2. *PJM Response*

On compliance, PJM is maintaining the same general reserve price capping framework, while incorporating the new 30-minute Reserve Requirement and Secondary Reserve product. As shown in the table below, PJM is maintaining the same upper limit on reserve prices—Synchronized Reserve prices are capped at two times the Reserve Penalty Factor, or \$1,700/MWh.³⁰ And, PJM is maintaining the same price cap of one Reserve Penalty Factor (\$850/MWh) for the reserve product that can meet only a single reserve requirement—the Secondary Reserve product, which can only contribute toward meeting the 30-minute Reserve Requirement.³¹ Because Non-Synchronized Reserve will

²⁸ See *PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,085, at P 15 (“[W]e clarify that the Remand Order did not remove the reserve price caps.”).

²⁹ 178 FERC ¶ 61,085, at P 17.

³⁰ Compare proposed Operating Agreement, Schedule 1, section 3.2.3A(d)(ii) (“[T]he Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.”) with Operating Agreement, Schedule 1, section 3.2.3A(d) (“[T]he 5-minute clearing price shall be . . . 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.”).

³¹ Compare proposed Operating Agreement, Schedule 1, sections 3.2.3A.01(d)(i) (Day-ahead Secondary Reserve Market) and 3.2.3A(d)(ii) (Real-time Secondary Reserve Market) with Operating Agreement, Schedule 1, section 3.2.3A.001(c) (“[T]he 5-minute clearing price for Non-Synchronized Reserve shall be

now be able to contribute toward the Primary Reserve Requirement *and* the 30-minute Reserve Requirement, PJM is adopting a price cap for Non-Synchronized Reserve of 1.5 times the Reserve Penalty Factor (i.e., \$1,275/MWh).³² Finally, PJM's approach will maintain the current allowed maximum energy component of the energy market LMP of \$3,700/MWh.

Reserve Product	Existing Maximum Price Levels (\$/MWh)	Maximum Price Levels With Secondary Reserve (\$/MWh)
Secondary Reserve	N/A	850
Non-Synchronized Reserve	850	1,275
Synchronized Reserve	1,700	1,700
Energy Component of LMP ³³	3,700	3,700

PJM's approach recognizes the relative hierarchy of reserve products and values each reserve product appropriately relative to each other, while maintaining the current price capping framework. In short, PJM proposes to retain the current approach of two times the Reserve Penalty Factor for the highest valued reserve product and one times the Reserve Penalty Factor for the lowest valued reserve product, and introduce an

... less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone.”).

³² See proposed Operating Agreement, Schedule 1, sections 3.2.3A.001(c)(i) (Day-ahead Non-Synchronized Reserve Market) and 3.2.3A.001(c)(ii) (Real-time Non-Synchronized Reserve Market).

³³ The maximum energy component of LMP for the purpose of this table is approximate. These values reflect a \$2,000/MWh energy offer and a shortage of all reserve products in the reserve zone and sub-zone. The values would be higher when there is a transmission constraint that is in violation and the marginal resource for energy induces forward flow on the violated constraint.

intermediate price cap of 1.5 times the Reserve Penalty Factor for the reserve product of intermediate value.

Failure to update the reserve price capping provisions would result in applying exactly the same price caps (\$850/MWh) for Non-Synchronized Reserve as would apply to the additional Secondary Reserve product, despite the fact that Secondary Reserve provides less reliability benefit because it can respond in 30 minutes, not in 10 minutes, and thus has less value. Because of its greater reliability value, Non-Synchronized Reserve can substitute for Secondary Reserve in meeting the 30-minute Reserve Requirement, but Secondary Reserve cannot substitute for Non-Synchronized Reserve in meeting the Primary Reserve Requirement.

This approach is consistent with the Commission's desire to allow for the introduction of a new 30-minute Reserve Requirement. A contrary approach of not allowing any portion of the price impacts associated with a shortage of the 30-minute Reserve Requirement to be reflected in the price of not meeting the Primary Reserve Requirement would prevent prices from differentiating the values of reserve products during certain conditions. Such an outcome would fail to communicate the greater reliability benefit of Non-Synchronized Reserves over 30-Minute Operating Reserves. That is, when the system is in a shortage of the 30-minute Reserve Requirement only, this method would produce the same clearing price for Secondary Reserve and Non-Synchronized Reserve (\$850/MWh), which inappropriately would price two reliability products the same, despite the fact that they provide different value. In short, such approach would not provide for a rational integration of this new product and reflecting both its value and its limitations in prices.

Finally, because energy and reserves are procured simultaneously through a joint co-optimization algorithm, reserve market clearing prices affect the energy price, and energy prices therefore reflect when the system is short a reserve requirement. Accordingly, to implement the addition of the 30-minute Reserve Requirement, PJM is revising its shortage pricing rules in Operating Agreement, Schedule 1, sections 2.5.1(a) and 2.6(b) to reflect the price capping resulting from the incorporation of the 30-minute Reserve Requirement.

While there are alternative just and reasonable approaches to reserve price capping that incorporate the new 30-minute Reserve Requirement and Secondary Reserve product,³⁴ PJM is not proposing to raise the overall energy market price above the existing maximum \$3,700/MWh level (LMP energy component only) at this time. Instead, PJM may explore market rule changes in this area with its stakeholders once a “circuit breaker” proposal has been implemented to protect the integrity of the market against sustained periods of shortage pricing. Indeed, PJM and its stakeholders are already currently investigating circuit breakers in the Energy Price Formation Senior Task Force. Thus, PJM may propose enhancements to the reserve price capping approach presented in this filing in a future filing.

III. IMPLEMENTATION SCHEDULE AND EFFECTIVE DATE

The Remand Order directed PJM to address, in its compliance filing, any necessary revisions to the effective dates for provisions referenced in the Remand Order.

³⁴ See, e.g., Motion for Clarification and Request for Expedited Action by February 11, 2022, of PJM Interconnection, L.L.C., Docket No. EL19-58-008, at 10-12 (Feb. 18, 2022).

PJM is targeting an October 1, 2022 implementation date, consistent with a schedule that will allow PJM to test its software and work with its vendors to identify and resolve any issues during the fall season. PJM's long-time vendor for coding, software, and market engine is still working on the updates. These tasks include inputs to Markets Gateway,³⁵ database work, and Day-ahead Energy Market engine and Markets Gateway results. The vendor's timeline extends PJM's requisite testing and implementation phases—including Real-time Energy Market and Markets Gateway product testing, end-to-end system integration testing, and market trials—which are anticipated to take 20 weeks to complete at a minimum.

An October 1, 2022 implementation date would accommodate: (i) the vendor's anticipated delivery date for the software updates, (ii) the requisite 20-week testing and implementation that must be completed by PJM after completion of all vendor deliveries, and (iii) PJM's historic avoidance of implementing major markets initiatives during the summer months, when there is a greater potential need to implement emergency procedures or operate the system more conservatively due to adverse weather conditions.³⁶

³⁵ Markets Gateway is a user interface portal whereby Market Sellers may submit offers into the Day-ahead Energy Market and the Real-time Energy Market. For more information on Markets Gateway, please see the PJM Markets Gateway User Guide, available here: <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.

³⁶ PJM's internal software and logic development protocols are specifically designed to avoid changes during periods of heightened reliability risk, as determined by PJM operations staff. *See, e.g.*, PJM Systems Operations Divisions, PJM Manual 13, Section 3.2 (Jan. 26, 2022), noting that during conservative operations, PJM may issue a Production System Change Freeze and will "refrain from updating business application systems, programs, data, systems software, hardware and other aspect of the information processing environment at PJM." The current version of PJM Manual 13 may be found here: <https://www.pjm.com/-/media/documents/manuals/m13.ashx>. PJM may also institute a Production System Change Freeze at other times, including Hot or Cold Weather alerts, or as system conditions may warrant.

Implementing these changes during the fall ensures that any issues that arise from testing occur during the shoulder months and not during the summer or winter peak months.

While PJM believes that the software changes necessary to implement the reserve market changes adopted by the Commission should be ready by October 1, 2022, PJM is submitting the enclosed Tariff and Operating Agreement revisions with a December 31, 9998 effective date. Such an effective date provides the flexibility to accommodate for potential delays in software development or if testing reveals issues that postpone implementation. PJM proposes to file by September 1, 2022, either a motion asking the Commission to make the enclosed revisions effective October 1, 2022, or an informational report on the implementation status and a projected effective date.

IV. DOCUMENTS ENCLOSED

PJM encloses the following:

1. This transmittal letter;
2. Attachment A – Sections of the Tariff and Operating Agreement (clean version), effective May 1, 2022;³⁷
3. Attachment B – Revised sections of the Tariff and Operating Agreement (redline version), effective December 31, 9998; and
4. Attachment C – Revised sections of the Tariff and Operating Agreement (clean version), effective December 31, 9998.

³⁷ PJM submits the currently effective Tariff and Operating Agreement provisions to remain in effect and therefore replaces the records previously accepted in this proceeding set to become effective May 1, 2022. *See* Remand Order at P 47 & n.106.

V. COMMUNICATIONS

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

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VI. SERVICE

PJM has served a copy of this filing on all PJM Members and on the affected state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,³⁸ PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <https://www.pjm.com/library/filing-order> 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

³⁸ See 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

utility regulatory commissions in the PJM Region³⁹ alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within twenty-four hours of the filing.

Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: <https://elibrary.ferc.gov/eLibrary/search> in accordance with the Commission's regulations and Order No. 714.⁴⁰

³⁹ PJM already maintains, updates, and regularly uses email lists for all PJM Members and affected state commissions.

⁴⁰ *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008), *final rule*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

VII. CONCLUSION

PJM respectfully requests that the Commission accept this compliance filing, as described herein.

Respectfully submitted,

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***Counsel for
PJM Interconnection, L.L.C.***

February 22, 2022

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 22nd day of February 2022.

/s/ Ryan J. Collins
Ryan J. Collins

Attachment A

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

Effective May 1, 2022

(Identified by Additional Cover Pages)

(Clean Format)

Sections of the
PJM Open Access Transmission Tariff

Effective May 1, 2022

(Clean Format)

Definitions – A - B

Abnormal Condition:

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Additional Day-ahead Scheduling Reserves Requirement:

“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

Affected System:

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership

of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

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

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

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

Annual Resource Price Adder:

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

Annual Revenue Rate:

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a

Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the

PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Demand Resource Constraint:

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30

and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Resource:

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in

question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

Base Day-ahead Scheduling Reserves Requirement:

“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

Base Load Generation Resource

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation

Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Demand Resource:

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

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

“Black Start Service” shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

“Border Yearly Charge” shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

“Breach” shall mean the failure of a party to perform or observe any material term or condition

of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

“Breaching Party” shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

“Business Day” shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

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

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – C-D

Canadian Guaranty:

“Canadian Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

“Cancellation Costs” shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

“Capacity” shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

“Capacity Export Transmission Customer” shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

“Capacity Import Limit” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

“Capacity Interconnection Rights” shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

“Capacity Performance Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

“Capacity Resource with State Subsidy” shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

Capacity Resource Clearing Price:

“Capacity Resource Clearing Price” shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

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

Capacity Transmission Injection Rights:

“Capacity Transmission Injection Rights” shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

“Charge Economic Maximum Megawatts” shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

“Charge Economic Minimum Megawatts” shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

“Charge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

“Charge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cleared Capacity Resource with State Subsidy:

“Cleared Capacity Resource with State Subsidy” shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting

engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

“Collateral” shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. “Collateral” shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

“Collateral Call” shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Commencement Date:

“Commencement Date” shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The “Committed Offer” shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

“Completed Application” shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Composite Energy Offer:

“Composite Energy Offer” for generation resources shall mean the sum (in \$/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in \$/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

Conditional Incremental Auction:

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

Conditioned State Support:

“Conditioned State Support” shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where “conditioned on clearing in any RPM Auction” refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

“CONE Area” shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

“Confidential Information” shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through

inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

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

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

“Contingent Facilities” shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request’s costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

“Controllable A.C. Merchant Transmission Facilities” shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

Cost of New Entry:

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

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not

be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

Credit Affiliate:

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

"Credit Available for Export Transactions" shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable

Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailement:

"Curtailement" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailement Service Provider:

“Curtailment Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

“Customer Interconnection Facilities” shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer’s side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

“Daily Deficiency Rate” shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Scheduling Reserves:

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

Day-ahead Scheduling Reserves Market:

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Scheduling Reserves Requirement:

“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:

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

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

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

Deactivation:

“Deactivation” shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

“Deactivation Avoidable Cost Credit” shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, Part V, section 115 .

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

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

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or (“DR Factor”) shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

“Designated Agent” shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

“Designated Entity” shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

“Direct Assignment Facilities” shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an

unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

“Discharge Economic Maximum Megawatts” shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

“Discharge Economic Minimum Megawatts” shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

“Discharge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate:

“Discharge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

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

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant

to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

“Dynamic Transfer” shall have the same meaning provided in the Operating Agreement.

Definitions – E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:

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

Electrical Distance:

“Electrical Distance” shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

“Eligible Customer” shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency Action:

“Emergency Action” shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

Emergency Condition:

“Emergency Condition” shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

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

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

“Energy Resource” shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

“Energy Settlement Area” shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

“Energy Transmission Injection Rights” shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

“Entity Providing Supply Services to Default Retail Service Provider” shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

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

Event of Default:

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Exercise of Buyer-Side Market Power:

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

“Export Nodal Reference Price” at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

“Export Transaction” shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

“Export Transaction Price Factor” for a prospective time interval shall be the greater of (i) PJM’s forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction’s dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

“Export Transaction Screening” shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Summer Demand Resource:

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

Extended Summer Resource Price Adder:

“Extended Summer Resource Price Adder” shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

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

External Resource:

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

Facilities Study:

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

“Financial Close” shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

“Financial Default” shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall mean Transmission Service under the Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

“Firm Transmission Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another

control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

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

Foreign Guaranty:

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

“Forward Hourly LMPs” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, “FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

“FTR Participant” shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM’s FTR market.

FTR Portfolio Auction Value:

“FTR Portfolio Auction Value” shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offers for a generation resource.

Full Notice to Proceed:

“Full Notice to Proceed” shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – L – M – N

Legacy Policy:

“Legacy Policy” shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will

not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner’s system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

“Load Interest” shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

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

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

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

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

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

Locational Deliverability Area Reliability Requirement:

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

Locational Price Adder:

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

Locational Reliability Charge:

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

Locational UCAP:

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

Locational UCAP Seller:

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

Long-lead Project:

“Long-lead Project” shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

“Marginal Value” shall mean the incremental change in system dispatch costs, measured as a \$/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

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

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Seller Offer Cap:

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

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

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

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

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

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities

available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

“Minimum Extended Summer Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

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

Minimum Participation Requirements:

“Minimum Participation Requirements” shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

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

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

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

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell

Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Services Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

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

Nominated Energy Efficiency Value:

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

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

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

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

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

Normal Minimum Generation:

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

Definitions – O – P - Q

Obligation:

“Obligation” shall mean all amounts owed to PJM Settlement for purchases from the PJM Markets, Transmission Service, (under both Tariff, Part II and Tariff, Part III), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJM Settlement in the future for capacity purchases within the PJM capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Offer Data:

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

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

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

On-Site Generators:

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

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

“Open Access Same-Time Information System,” “PJM Open Access Same-Time Information System” or “OASIS” shall mean the electronic communication and information system and

standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve Demand Curve:

"Operating Reserve Demand Curve" shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement and the value placed on maintaining that megawatt level of reserve, expressed in \$/MWh.

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy

from the external Generation Capacity Resource to loads in the PJM Region in a manner comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

“Opportunity Cost” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

OPSI Advisory Committee:

“OPSI Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

“Option to Build” shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

“Optional Interconnection Study” shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

“Optional Interconnection Study Agreement” shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

“Part I” shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

“Part II” shall mean Tariff, Part II, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

“Part III” shall mean Tariff, Part III, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

“Part IV” shall mean Tariff, Part IV, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

“Part V” shall mean Tariff, Part V, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

“Part VI” shall mean Tariff, Part VI, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

“Participant” shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer.

Parties:

“Parties” shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

“Peak-Hour Dispatch” shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete

start and shutdown cycle), plus 10% of such costs *only for the 2022/2023 Delivery Year*, for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate, plus 10% of such costs *only for the 2022/2023 Delivery Year*, under the same conditions as described above for the Day-ahead Energy Market.

Peak Market Activity:

“Peak Market Activity” shall mean a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of Tariff, Attachment Q, section VII.A. Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

Peak Season:

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

Percentage Internal Resources Required:

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

Performance Assessment Interval:

“Performance Assessment Interval” shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September.

Permissible Technological Advancement:

“Permissible Technological Advancement” shall mean a proposed technological change such as an advancement to turbines, inverters, plant supervisory controls or other similar advancements to the technology proposed in the Interconnection Request that is submitted to the Transmission Provider no later than the return of an executed Facilities Study Agreement (or, if a Facilities Study is not required, prior to the return of an executed Interconnection Service Agreement). Provided such change may not: (i) increase the capability of the Generating Facility as specified in the original Interconnection Request; (ii) represent a different fuel type from the original Interconnection Request; or (iii) cause any material adverse impact(s) on the Transmission

System with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response. If the proposed technological advancement is a Permissible Technological Advancement, no additional study will be necessary and the proposed technological advancement will not be considered a Material Modification.

PJM:

“PJM” shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

“PJM Administrative Service” shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

“PJM Entities” shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM’s officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

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

PJM Interchange Energy Market:

“PJM Interchange Energy Market” shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

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

PJM Interchange Import:

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

PJM Liaison:

“PJM Liaison” shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

“PJM Management” shall mean the officers, executives, supervisors and employee managers of PJM.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Markets:

“PJM Markets” shall mean the PJM Interchange Energy Market, capacity markets, including the RPM auctions, and any other market operated by PJM, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions, Financial Transmission Rights

transactions, or transactions in any other market operated under the Agreements within the PJM Region, wherein Market Participants may incur Obligations to PJM and/or PJMSettlement.

PJM Market Rules:

“PJM Market Rules” shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

“PJM Net Assets” shall mean the total assets per PJM’s consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

“PJM Region” shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:

“PJM Regional Practices Document” shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to RAA, Schedule 4.1, as approved by the PJM Board.

PJM Region Peak Load Forecast:

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

PJM Region Reliability Requirement:

“PJM Region Reliability Requirement” shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast,

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

PJMSettlement:

“PJM Settlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” “OATT,” or “PJM Open Access Transmission Tariff” shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

“Plan” shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

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

Planned External Financed Generation Capacity Resource:

“Planned External Financed Generation Capacity Resource” shall mean a Planned External Generation Capacity Resource that, prior to August 7, 2015, has an effective agreement that is the equivalent of an Interconnection Service Agreement, has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close, and has secured at least 50 percent of the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Planned External Generation Capacity Resource:

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

Planned Financed Generation Capacity Resource:

“Planned Financed Generation Capacity Resource” shall mean a Planned Generation Capacity Resource that, prior to August 7, 2015, has an effective Interconnection Service Agreement and has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close.

Planned Generation Capacity Resource:

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

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Planning Period Balance:

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

Planning Period Quarter:

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

Point(s) of Delivery:

“Point(s) of Delivery” shall mean the point(s) on the Transmission Provider’s Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

“Point of Interconnection” shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

“Point(s) of Receipt” shall mean point(s) of interconnection on the Transmission Provider’s Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

“Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

“Power Purchaser” shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

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

PRD Provider:

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

PRD Reservation Price:

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

PRD Substation:

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

Pre-Confirmed Application:

“Pre-Confirmed Application” shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

“Pre-Emergency Load Response Program” shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Pre-Expansion PJM Zones:

“Pre-Expansion PJM Zones” shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC (“MAIT”) (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

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

Primary Reserve:

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

Primary Reserve Alert

“Primary Reserve Alert” shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the demand for Primary Reserves in a Reserve Zone or Reserve Sub-zone, as defined by the Operating Reserve Demand Curve for Primary Reserve. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Principal:

“Principal” shall mean (i) the chief executive officer or senior manager that controls or directs strategy for the Participant, (ii) the chief legal officer or general counsel, (iii) the chief financial officer or senior manager that controls or directs the financial affairs and investments of the Participant, (iv) the chief risk officer or senior manager responsible for managing commodity and derivatives market risks, and (v) the officer or senior manager responsible for or to be responsible for transactions in the applicable PJM Markets. If, due to the Participant’s business enterprise, structure or otherwise, the functions attributed to any of such Principals are performed by an individual or entity separate from the Participant (such as a risk management department in an affiliate, or a director or manager at an entity that controls or invests in the Participant), then for that Participant the term Principal shall mean that individual, or the senior officer or manager of that entity, that performs such function.

Prior CIL Exception External Resource:

“Prior CIL Exception External Resource” shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a

portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

“Project Financing” shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer’s obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

“Project Finance Entity” shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer’s obligations under the corresponding power purchase agreement.

Projected EAS Dispatch:

“Projected EAS Dispatch” shall mean, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource’s offer and operating parameters. For combustion turbine units only, the cost-based energy offer will include a 10 percent adder *only for the 2022/2023 Delivery Year*.

Projected PJM Market Revenues:

“Projected PJM Market Revenues” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Provisional Interconnection Service:

“Provisional Interconnection Service” shall mean interconnection service provided by Transmission Provider associated with interconnecting the Interconnection Customer’s Generating Facility to Transmission Provider’s Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interconnection Service Agreement and, if applicable, the Tariff.

Pseudo-Tie:

“Pseudo-Tie” shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

“Public Policy Objectives” shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

“Public Policy Requirements” shall have the same meaning provided in the Operating Agreement.

Qualifying Transmission Upgrade:

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

Queue Position:

“Queue Position” shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

Definitions – R - S

Ramping Capability:

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

Real-time Congestion Price:

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

Real-time Loss Price:

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

Real-time Energy Market:

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

Real-time Offer:

“Real-time Offer” shall mean a new offer or an update to a Market Seller’s existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

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

Real-time Settlement Interval:

“Real-time Settlement Interval” shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

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

Reasonable Efforts:

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

Receiving Party:

“Receiving Party” shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

“Referral” shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

“Reference Resource” shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh.

Regional Entity:

“Regional Entity” shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

“Regional Transmission Expansion Plan” shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

“Regional Transmission Group” or “RTG” shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and

decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

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

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

“Reliability Assurance Agreement” or “PJM Reliability Assurance Agreement” shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

“Reliability Pricing Model Auction” or “RPM Auction” shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

“Regional Transmission Enhancements” shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B (“Appendix B Agreement”) designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

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

Reserve Penalty Factor:

“Reserve Penalty Factor” shall mean the cost, in \$/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

“Reserve Sub-zone” shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

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

Residual Auction Revenue Rights:

“Residual Auction Revenue Rights” shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

“Residual Metered Load” shall mean all load remaining in an electric distribution company’s fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource Substitution Charge:

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

Revenue Data for Settlements:

“Revenue Data for Settlements” shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

“RPM Seller Credit” shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

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

Schedule of Work:

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

Scope of Work:

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

Seasonal Capacity Performance Resource:

“Seasonal Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Systems:

“Secondary Systems” shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors,

electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

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

Security:

“Security” shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer’s responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

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

Self-Supply Entity:

“Self-Supply Entity” shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where “vertically integrated utility” means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; “single customer entity” means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and “public power entity” means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

“Self-Supply Seller” shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where “vertically integrated utility” means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and “public power entity” means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

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

Service Agreement:

“Service Agreement” shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

“Service Commencement Date” shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

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

“Short-Term Firm Point-To-Point Transmission Service” shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

“Short-term Project” shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

“Short-Term Resource Procurement Target” shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual

Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:

“Short-Term Resource Procurement Target Applicable Share” shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

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

Small Commercial Customer:

“Small Commercial Customer,” as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a “small commercial customer” under the terms of the applicable RERRA’s program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

“Small Generation Resource” shall mean an Interconnection Customer’s device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer’s Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

“Small Inverter Facility” shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

“Small Inverter ISA” shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

“Special Member” shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

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

Spot Market Energy:

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

“Start Additional Labor Costs” shall mean additional labor costs for startup required above normal station manning levels.

Start-Up Costs:

“Start-Up Costs” shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

“State” shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

“State Commission” shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

“State Subsidy” shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

- (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or
- (2) will support the construction, development, or operation of a new or existing Capacity Resource; or
- (3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity’s obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm’s length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction,

development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

- (i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);
- (ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and
- (iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State of Charge:

“State of Charge” shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using minimum and maximum charge and discharge limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant’s obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

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

Sub-Annual Resource Constraint:

“Sub-Annual Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

“Sub-Annual Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

“Sub-Annual Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE,

compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Sub-meter:

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

“Summer-Period Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

“Surplus Interconnection Customer” shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

“Surplus Interconnection Request” shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

“Surplus Interconnection Service” shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

“Switching and Tagging Rules” shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

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

Synchronized Reserve Event:

“Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

System Condition:

“System Condition” shall mean a specified condition on the Transmission Provider’s system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer’s Service Agreement.

System Energy Price:

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

“System Impact Study” shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer’s Customer Facility can be interconnected with the Transmission System and an estimate of the

Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

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

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the

relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric

distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated

hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
- b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
- c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
- d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the

matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

- b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

(“Pilot Period”). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Demand Resource Provision of Synchronized Reserve or Day-ahead Scheduling Reserves.

(a) A Batch Load Demand Resource may provide Synchronized Reserve or Day-ahead Scheduling Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of “Batch Load Demand Resource” pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.

(b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection’s filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection’s calling of a Synchronized Reserve Event, or to such

instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Day-ahead Scheduling Reserves to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the Day-Ahead Scheduling Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;

v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each End-Use Customer site must meet the requirements for market participation by a demand resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by a demand resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those

Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

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

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

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

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Demand Resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

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

it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

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

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers,

continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

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

1.7.8 Generating Market Buyer Resources.

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

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

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

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

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

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

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

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

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

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

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

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), “net output” of a generation facility during any month means the facility’s gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility’s or a Market Seller’s monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as “remote self-supply of Station Power”), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility’s negative net output from Market Seller’s generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A; Tariff, Schedule 2; Tariff, Schedule 3; Tariff, Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

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

(iv) The Office of the Interconnection is not responsible for determining Relevant Electric Retail Regulatory Authority-jurisdictional retail rates, and the monthly netting provision in section 1.7.10(d)(i) above does not determine whether a retail sale of station power has occurred in a month. Furthermore, notwithstanding any provision of subsection (d)(i) or (d)(ii) to the contrary, any net output determined for a Market Seller for Station Power purposes shall, as more fully set forth in the PJM manuals, take account of MWh values submitted to the Office of the Interconnection via its metering reporting systems by the Market Seller or the applicable Electric Distribution Company designated to make such submission, that reflect the Market Seller's purchase of energy at retail to meet its Station Power needs.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJM Settlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

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

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

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

1.7.14 PJM Manuals.

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

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 [Reserved.]

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or demand resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering

Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

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

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

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

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

1.7.19 Ramping.

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

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Tariff, Attachment K-Appendix, section 2.5(d) and the parallel provision of Operating Agreement, Schedule 1, section 2.5(d), all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic

area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

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

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. Resources, the entire output of which has been designated as emergency energy, and resources that aren't available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

(d) The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability of a generation

resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.

- (e) All Non-Synchronized Reserve offers shall be for \$0.00/MWh.

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

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

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

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

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party

under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

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

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

1.7.20 Communication and Operating Requirements.

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

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or

change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

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

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

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

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.10 Scheduling.

1.10.1 General.

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

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

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the

Day-ahead Energy Market may specify the price (such price not to exceed \$2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-Time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to \$2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an “Up-to Congestion Transaction.” Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to \$2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Section 1.10.9B, Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

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

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

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

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

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;
- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or

prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour;

ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour;

a) x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with: a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, \$1,000/megawatt hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, \$1,100/megawatt-hour; and

x) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day.

The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and
- iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

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

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify

amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j)

A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

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

(m)

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

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

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

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

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

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

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load

reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

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

- (a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.
- (b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.
- (c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.
- (d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.
- (e) Hydropower units, excluding pumped storage units, may only be self-scheduled.
- (f) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

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

with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

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

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

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

1.10.6 External Market Buyers.

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

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of

the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

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

1.10.7 Bilateral Transactions.

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

1.10.8 Office of the Interconnection Responsibilities.

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

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

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

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

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

Market, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

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

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the

hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

- (i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for

an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; and (6) fixed output indicator. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic

Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; and (6) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

(c) For Demand Resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

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

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources 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.

2.2 General.

The Office of the Interconnection calculates Locational Marginal Prices separately from and subsequent to the security-constrained unit commitment and security-constrained economic dispatch of the system, the latter of which is referred to as the dispatch run. The calculation of Locational Marginal Prices, which occurs in a process referred to as the pricing run, is based on the same optimization problem as the security-constrained economic dispatch. The objective of both the dispatch run and the pricing run is to serve load and meet reserve requirements at the least cost while respecting transmission constraints. However, Integer Relaxation is applied only to Eligible Fast-Start Resources committed in the pricing run to provide energy.

In the dispatch run a commitment state of 1 represents a resource is committed and 0 represents a resource is not committed. In the pricing run Integer Relaxation allows the commitment state of a committed Eligible Fast-Start Resource to be lowered to any value between 0 and 1, inclusive of 0 and 1. This in turn allows the optimization problem in the pricing run to use any fraction of a committed Eligible Fast-Start Resource's output, including an amount less than the resource's offered Economic Minimum output, in the determination of Locational Marginal Prices.

The process for the determination of Locational Marginal Prices in the Day-ahead Energy Market is described in Tariff, Attachment K-Appendix, section 2.6 and the process for the determination of Locational Marginal Prices in the Real-time Energy Market is described in Tariff, Attachment K-Appendix, section 2.5.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Tariff, Attachment K-Appendix, section 2.4. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any monitored transmission constraints that may exist.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Tariff, Attachment K-Appendix, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.

(c) In performing the Real-time Price calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as described in Tariff, Attachment K-Appendix, section 2.4 as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative), including Transmission Constraint Penalty Factors, associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the

next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(d) During the Operating Day, the calculation set forth in Tariff, Attachment K-Appendix, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

2.5.1 Declaration of Shortage Pricing

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage for the purposes of declaring shortage pricing as further described in the PJM Manuals. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, Real-time Prices shall be calculated as described in Tariff, Attachment K-Appendix, section 2.5 and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When the Real-time Price software determines that a Primary Reserve shortage and/or a Synchronized Reserve shortage exists, whereby the reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the Office of Interconnection shall implement shortage pricing. During shortage pricing, the Real-time Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Tariff, Attachment K-Appendix, section 2.5 above shall be calculated as described below. Shortage pricing shall exist until the Real-time Price software program is able to meet the specified reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect.

(b) If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable. The Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM

Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable. The Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable, until the Manual Load Dump Action has been terminated.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Tariff, Attachment K-Appendix, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, Day-ahead Scheduling Reserve offers, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Day-ahead Price at that bus.

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.

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

(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 $(A \cdot B) - (C + D)$. 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:

$$Ramp_Request_t = (Dispatch_target_{t-1} - AOutput_{t-1}) / (LTime_{t-1})$$

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

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. LTime = 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) 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 assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all Real-time Settlement Intervals the resource was assigned 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 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 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 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 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 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 by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each 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.

Sections of the
PJM Operating Agreement

Effective May 1, 2022

(Clean Format)

Definitions A - B

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

Act:

“Act” shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

“Active and Significant Business Interest” is a term that shall be used to assess the scope of a Member’s PJM membership and shall be based on a Member’s activity in the PJM RTO and/or Interchange Energy Markets. A Member’s Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member’s PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member’s public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member’s recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates’ interests within the PJM footprint.

Additional Day-ahead Scheduling Reserves Requirement:

“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

Affected Member:

“Affected Member” shall mean a Member of PJM which as a result of its participation in PJM’s markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for

purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreement, Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Agreement,” “Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

Annual Meeting of the Members:

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Associate Member:

“Associate Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Commission:

“Authorized Commission” shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

“Authorized Person” shall have the meaning set forth in Operating Agreement, section 18.17.4.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Base Day-ahead Scheduling Reserves Requirement:

“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

Batch Load Demand Resource:

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

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such

consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

“Board Member” shall mean a member of the PJM Board.

Definitions C - D

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Catastrophic Force Majeure:

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

Charge Economic Maximum Megawatts:

“Charge Economic Maximum Megawatts” shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

“Charge Economic Minimum Megawatts” shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

“Charge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

“Charge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Committed Offer:

The “Committed Offer shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Compliance Monitoring and Enforcement Program:

“Compliance Monitoring and Enforcement Program” shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

Composite Energy Offer:

“Composite Energy Offer” for generation resources shall mean the sum (in \$/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in \$/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A and the PJM Manuals.

Congestion Price:

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or “Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other

transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the extent that energy serves that Member's own load.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45) Schedule A. The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C, Attachment 3, section 2.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment Service Provider:

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

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Scheduling Reserves:

“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the ReliabilityFirst Corporation and SERC.

Day-ahead Scheduling Reserves Market:

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Scheduling Reserves Requirement:

“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:

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

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

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

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default Allocation Assessment:

“Default Allocation Assessment” shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

“Demand Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Designated Entity:

“Designated Entity” shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

Direct Charging Energy:

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

“Discharge Economic Maximum Megawatts” shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

“Discharge Economic Minimum Megawatts” shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

“Discharge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate:

“Discharge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

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

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Dynamic Transfer:

“Dynamic Transfer” shall mean a Pseudo-Tie or Dynamic Schedule.

Definitions E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall mean an enhancement or expansion described in Operating Agreement, Schedule 6, section 1.5.7(b) (i) – (iii) that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

“Effective Date” shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EIDSN, Inc.:

“EIDSN, Inc.” shall mean the nonstock, nonprofit corporation, formerly known as Eastern Interconnection Data Sharing Network, Inc., or any successor thereto, that is operated primarily for the purpose of developing operating tools and the facilitation of the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among Reliability Coordinators and other relevant parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk electric system in the Eastern Interconnection.

Electric Distributor:

“Electric Distributor” shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency:

“Emergency” shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Member Committee classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Equivalent Load:

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

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

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

External Resource:

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

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for an Operating Day.

Finance Committee:

“Finance Committee” shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offer(s) for a generation resource.

Definitions I - L

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall mean a reliability-based transmission enhancement or expansion that the Office of the Interconnection has identified to resolve a need that must be addressed within three years or less from the year the Office of the Interconnection identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3.

Inadvertent Interchange:

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

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean the cost in dollars per MWh of providing an additional MWh from a synchronized unit. It consists primarily of the cost of fuel, as determined by the unit’s incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances, tax credits, and energy market opportunity costs.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Information Request:

“Information Request” shall mean a written request, in accordance with the terms of the Operating Agreement for disclosure of confidential information pursuant to Operating Agreement, section 18.17.4.

Integer Relaxation:

“Integer Relaxation” shall mean the process by which the commitment status variable for an Eligible Fast-Start Resource is allowed to vary between zero and one, inclusive of zero and one, as further described in Operating Agreement, Schedule 1, section 2.2.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Internal Market Buyer:

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

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

LLC:

“LLC” shall mean PJM Interconnection, L.L.C., a Delaware limited liability company.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Reduction Event:

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

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Local Plan:

“Local Plan” shall include Supplemental Projects as identified by the Transmission Owners within their zone and Subregional RTEP projects developed to comply with all applicable reliability criteria, including Transmission Owners’ planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

Locational Marginal Price:

“Locational Marginal Price” or “LMP” shall mean the market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Long-lead Project:

“Long-lead Project” shall mean a transmission enhancement or expansion with an in-service date more than five years from the year in which, pursuant to Operating Agreement, Schedule 6,

section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Definitions M - N

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Market Buyer:

“Market Buyer” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and/or PJM Settlement in Tariff, Attachment Q, and that is otherwise able to make purchases in the PJM Interchange Energy Market.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” shall mean the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM.

Market Operations Center:

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

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, and/or an Economic Load Response Participant, except when that term is used in or pertaining to Tariff, Attachment M, Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4. “Market Participant,” when such term is used in Tariff, Attachment M, shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but

does not purchase or sell energy at wholesale. “Market Participant,” when such term is used in or pertaining to Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4, shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, an FTR Participant, a Capacity Market Buyer, or a Capacity Market Seller.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Seller:

“Market Seller” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and/or PJM Settlement in Tariff, Attachment Q, and that is otherwise able to make sales in the PJM Interchange Energy Market.

Maximum Emergency:

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

Maximum Generation Emergency:

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

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Operating Agreement, Schedule 4.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

Minimum Generation Emergency:

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

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and

unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

"Multi-Driver Project" shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation, or any successor thereto.

NERC Functional Model:

"NERC Functional Model" shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Interchange Distribution Calculator:

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

NERC Reliability Standards:

“NERC Reliability Standards” shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.

NERC Rules of Procedure: “NERC Rules of Procedure” shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Network Resource:

“Network Resource” shall have the meaning specified in the PJM Tariff.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

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

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Non-Disclosure Agreement:

“Non-Disclosure Agreement” shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Operating Agreement, section, the form of which is appended to this Agreement as Operating Agreement, Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Nonincumbent Developer:

“Nonincumbent Developer” shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J.

Non-Regulatory Opportunity Cost:

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

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of

the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, 1.5A.6.

Normal Maximum Generation:

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

Normal Minimum Generation:

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

Definitions O - P

Offer Data:

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

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

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

On-Site Generators:

“On-Site Generators” shall mean generation facilities or portions of a generation facility (including Behind The Meter Generation) that (i) are not Generation Capacity Resources, (ii) are not injecting into the grid for the portion of a generation facility that participates as an Economic Load Response Participant or as a Demand Resource, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-time Information System:

“Open Access Same-Time Information System,” “PJM Open Access Same-time Information System” or “OASIS” shall mean the electronic communication system and information system and standards of conduct contained in Part 37 and Part 38 of the Commission’s regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Operator-initiated Commitment:

“Operator-initiated Commitment” shall mean a commitment after the Day-ahead Energy Market and Day-ahead Scheduling Reserves Market, whether manual or automated, for a reason other than minimizing the total production costs of serving load.

Original PJM Agreement:

“Original PJM Agreement” shall mean that certain agreement between certain of the Members, originally dated September 26, 1956, and as amended and supplemented up to and including December 31, 1996, relating to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and; (ii) does not qualify for the Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer sectors.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM

Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Dispute Resolution Procedures:

“PJM Dispute Resolution Procedures” shall mean the procedures for the resolution of disputes set forth in Operating Agreement, Schedule 5.

PJM Governing Agreements:

“PJM Governing Agreements” shall mean the PJM Open Access Transmission Tariff, the Operating Agreement, the Consolidated Transmission Owners Agreement, the Reliability Assurance Agreement, or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and any of its Members.

PJM Interchange:

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

PJM Interchange Energy Market:

“PJM Interchange Energy Market” shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix.

PJM Interchange Export:

“PJM Interchange Export” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load is exceeded by the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the interval scheduled deliveries of Spot

Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

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

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Mid-Atlantic Region:

“PJM Mid-Atlantic Region” shall mean the aggregate of the Transmission Facilities of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

PJM Region:

“PJM Region” shall mean the aggregate of the Zones within PJM as set forth in Tariff, Attachment J.

PJMSettlement:

“PJMSettlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM South Region:

“PJM South Region” shall mean the Transmission Facilities of Virginia Electric and Power Company.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” or “PJM Open Access Transmission Tariff” shall mean that certain “PJM Open Access Transmission Tariff”, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

PJM West Region:

“PJM West Region” shall mean the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Affiliate Companies; The Dayton Power and Light Company; the Duquesne Light Company; American Transmission Systems, Incorporated; Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc. and East Kentucky Power Cooperative, Inc.

Planning Period:

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

Planning Period Balance:

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

Planning Period Quarter:

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

Point-to-Point Transmission Service:

“Point-to-Point Transmission Service” shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Delivery under Tariff, Part II.

PRD Curve:

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

PRD Provider:

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

PRD Reservation Price:

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

PRD Substation:

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

Pre-Emergency Load Response Program:

“Pre-Emergency Load Response Program” shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-appendix, section 8.

President:

“President” shall have the meaning specified in Operating Agreement, section 9.2.

Price Responsive Demand:

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

Primary Reserve:

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

Primary Reserve Alert:

“Primary Reserve Alert” shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Prohibited Securities:

“Prohibited Securities” shall mean the Securities of a Member, Eligible Customer, or Nonincumbent Developer, or their Affiliates, if:

(1) the primary business purpose of the Member or Eligible Customer, or their Affiliates, is to buy, sell or schedule energy, power, capacity, ancillary services or transmission services as indicated by an industry code within the “Electric Power Generation, Transmission, and

Distribution” industry group under the North American Industry Classification System (“NAICS”) or otherwise determined by the Office of the Interconnection;

(2) the Nonincumbent Developer has been pre-qualified as eligible to be a Designated Entity pursuant to Operating Agreement, Schedule 6;

(3) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during its most recently completed fiscal year is equal to or greater than 0.5% of its gross revenues for the same time period; or

(4) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during the prior calendar year is equal to or greater than 3% of the total transactions for which PJM Settlement is a Counterparty pursuant to Operating Agreement, section 3.3 for the same time period.

The Office of the Interconnection shall compile and maintain a list of the Prohibited Securities publicly traded and post this list for all employees and distribute the list to the Board Members.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Pseudo-Tie:

“Pseudo-Tie shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Public Policy Objectives:

“Public Policy Objectives” shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations.

Public Policy Requirements:

“Public Policy Requirements” shall refer to policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government,

where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity.

Definitions Q - R

Ramping Capability:

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

Real-time Congestion Price:

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

Real-time Loss Price:

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

Real-time Offer:

“Real-time Offer” shall mean a new offer or an update to a Market Seller’s existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

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

Real-time Energy Market:

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

Real-time Settlement Interval:

“Real-time Settlement Interval” shall mean the interval used by settlements, which shall be every five minutes.

Real-time State of Charge:

“Real-time State of Charge” shall mean the current State of Charge of an Energy Storage Resource Model Participant, measured in units of megawatt-hours.

Real-time System Energy Price:

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

Regional Entity:

“Regional Entity” shall mean an organization that NERC has delegated the authority to propose and enforce reliability standards pursuant to the Federal Power Act.

Regional RTEP Project:

“Regional RTEP Project” shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Registered Entity:

“Registered Entity” shall mean the entity registered under the NERC Functional Model and NERC Rules of Procedures for the purpose of compliance with NERC Reliability Standards and responsible for carrying out the tasks within a NERC function without regard to whether a task or tasks are performed by another entity pursuant to the terms of the PJM Governing Agreements.

Regulation:

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

Regulation Zone:

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

Related Parties:

“Related Parties” shall mean, solely for purposes of the governance provisions of the Operating Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of the Operating Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

“Reliability Assurance Agreement” or “PJM Reliability Assurance Agreement” shall mean that certain Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC. No. 44, and as amended from time to time thereafter.

Reliability Coordinator:

“Reliability Coordinator” shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

Reserve Penalty Factor:

“Reserve Penalty Factor” shall mean the cost, in \$/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

“Reserve Sub-zone” shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

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

Residual Auction Revenue Rights:

“Residual Auction Revenue Rights” shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2(h), and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2, and the parallel provisions of Attachment K-

Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

“Residual Metered Load” shall mean all load remaining in an electric distribution company’s fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Revenue Data for Settlements:

“Revenue Data for Settlements” shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

Definitions S – T

Sector Votes:

“Sector Votes” shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

“Securities” shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

“Senior Standing Committees” shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

“SERC” or “Southeastern Electric Reliability Council” shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

“Short-term Project” shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

“Special Member” shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

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

Spot Market Energy:

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Standing Committees:

“Standing Committees” shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start-Up Costs:

“Start-Up Costs” shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

“State” shall mean the District of Columbia and any State or Commonwealth of the United States.

State Certification:

“State Certification” shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State of Charge:

“State of Charge” shall mean the operating parameter that represents the quantity of physical energy stored (measured in units of megawatt-hours) in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using Charge and Discharge Economic Minimum and Maximum Megawatts limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant’s obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

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

Sub-meter:

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Subregional RTEP Project:

“Subregional RTEP Project” shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

“Supplemental Project” shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

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

Synchronized Reserve Event:

“Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

System:

“System” shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3 or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Party Request:

“Third Party Request” shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

“Tie Line” shall have the same meaning provided in the Open Access Transmission Tariff.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the

offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Customer:

“Transmission Customer” shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

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

Transmission Loading Relief:

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

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Operator:

“Transmission Operator” shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall mean an upgrade to a Transmission Owner’s own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the

relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric

distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated

hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
- b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
- c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
- d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the

matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

- b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

("Pilot Period"). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Demand Resource Provision of Synchronized Reserve or Day-ahead Scheduling Reserves.

(a) A Batch Load Demand Resource may provide Synchronized Reserve or Day-ahead Scheduling Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Demand Resource" pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.

(b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection's filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such

instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Day-ahead Scheduling Reserves to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the Day-Ahead Scheduling Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;

v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each End-Use Customer site must meet the requirements for market participation by a demand resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by a demand resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those

Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

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

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

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

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Demand Resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

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

and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

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

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM

Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

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

1.7.8 Generating Market Buyer Resources.

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

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

- (i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its InSchedule and ExSchedule tools.
- (ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.
- (iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all

reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

- (iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.
- (v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.
- (vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

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

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

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

- (i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.
- (ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless

the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A; Tariff, Schedule 2; Tariff, Schedule 3; Tariff, Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

- (iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.
- (iv) The Office of the Interconnection is not responsible for determining Relevant Electric Retail Regulatory Authority-jurisdictional retail rates, and the monthly netting provision in section 1.7.10(d)(i) above does not determine whether a retail sale of station power has occurred in a month. Furthermore, notwithstanding any provision of subsection (d)(i) or (d)(ii) to the contrary, any net output determined for a Market Seller for Station Power purposes shall, as more fully set forth in the PJM manuals, take account of MWh values submitted to the Office of the Interconnection via its metering reporting systems by the Market Seller or the applicable Electric Distribution Company designated to make such submission, that reflect the Market Seller's purchase of energy at retail to meet its Station Power needs.

1.7.11 Emergencies.

- (a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market

Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

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

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

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

1.7.14 PJM Manuals.

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

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 [Reserved.]

1.7.18 Regulation.

- (a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or demand resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.
- (b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.
- (c) The Regulation range of a generation unit or demand resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.
- (d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.
- (e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

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

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Tariff, Attachment K-Appendix, section 2.5(d) and the parallel provision of Operating Agreement, Schedule 1, section 2.5(d), all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

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

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. Resources, the entire output of which has been designated as emergency energy, and resources that aren't available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

(d) The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability of a generation resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.

(e) All Non-Synchronized Reserve offers shall be for \$0.00/MWh.

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

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

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead

Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

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

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

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

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

transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

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

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

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

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

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

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.10 Scheduling.

1.10.1 General.

- (a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.
- (b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.
- (c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.
- (d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection:

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed \$2,000/MWh), if any, at which the

export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-Time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to \$2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an “Up-to Congestion Transaction.” Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to \$2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load

is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Section 1.10.9B, Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.
- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;
- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the

Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour;
- ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour;
- x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:
 - a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;
 - b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, \$1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and
 - c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, \$1,100/megawatt-hour; and

- x) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and
- iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such

resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

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

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

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer

must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

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

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

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures

between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

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

- (a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.
- (b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.
- (c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.
- (d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

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

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

1.10.3 Self-scheduled Resources.

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

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

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

(f) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled

resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

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

1.10.5 External Resources.

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

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

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

1.10.6 External Market Buyers.

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

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

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

1.10.7 Bilateral Transactions.

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

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for

Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

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

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that

Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

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

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day.

However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; and (6) fixed output indicator. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; and (6) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

(c) For Demand Resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

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

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources 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.

2.2 General.

The Office of the Interconnection calculates Locational Marginal Prices separately from and subsequent to the security-constrained unit commitment and security-constrained economic dispatch of the system, the latter of which is referred to as the dispatch run. The calculation of Locational Marginal Prices, which occurs in a process referred to as the pricing run, is based on the same optimization problem as the security-constrained economic dispatch. The objective of both the dispatch run and the pricing run is to serve load and meet reserve requirements at the least cost while respecting transmission constraints. However, Integer Relaxation is applied only to Eligible Fast-Start Resources committed in the pricing run to provide energy.

In the dispatch run a commitment state of 1 represents a resource is committed and 0 represents a resource is not committed. In the pricing run Integer Relaxation allows the commitment state of a committed Eligible Fast-Start Resource to be lowered to any value between 0 and 1, inclusive of 0 and 1. This in turn allows the optimization problem in the pricing run to use any fraction of a committed Eligible Fast-Start Resource's output, including an amount less than the resource's offered Economic Minimum output, in the determination of Locational Marginal Prices.

The process for the determination of Locational Marginal Prices in the Day-ahead Energy Market is described in Operating Agreement, Schedule 1, section 2.6 and the process for the determination of Locational Marginal Prices in the Real-time Energy Market is described in Operating Agreement, Schedule 1, section 2.5.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Operating Agreement, Schedule 1, section 2.4. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any monitored transmission constraints that may exist.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Operating Agreement, Schedule 1, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.

(c) In performing the Real-time Price calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as described in Operating Agreement, Schedule 1, section 2.4 as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative), including Transmission Constraint Penalty Factors, associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the

bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(d) During the Operating Day, the calculation set forth in Operating Agreement, Schedule 1, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

2.5.1 Declaration of Shortage Pricing

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage for the purposes of declaring shortage pricing as further described in the PJM Manuals. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, Real-time Prices shall be calculated as described in Operating Agreement, Schedule 1, section 2.5 and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When the Real-time Price software determines that a Primary Reserve shortage and/or a Synchronized Reserve shortage exists, whereby the reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the Office of Interconnection shall implement shortage pricing. During shortage pricing, the Real-time Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Operating Agreement, Schedule 1, section 2.5 above shall be calculated as described below. Shortage pricing shall exist until the Real-time Price software program is able to meet the specified reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect.

(b) If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a

transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable. The Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement are

incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable. The Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable, until the Manual Load Dump Action has been terminated.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Operating Agreement, Schedule 1, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, Day-ahead Scheduling Reserve offers, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Day-ahead Price at that bus.

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.

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

(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:

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

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

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 $(A \times B) - C$.

(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:

$$Ramp_Request_t = (Dispatch_target_{t-1} - AOutput_{t-1}) / (LTime_{t-1})$$

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

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. LTime = 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) 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 assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all Real-time Settlement Intervals the resource was assigned 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 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 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 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 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 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 by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each 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.

Attachment B

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

Effective December 31, 9998

(Identified by Additional Cover Pages)

(Marked/Redline Format)

Sections of the
PJM Open Access Transmission Tariff

Effective December 31, 9998

(Marked/Redline Format)

Definitions – A - B

30-minute Reserve:

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

~~Additional Day-ahead Scheduling Reserves Requirement:~~

~~“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.~~

Affected System:

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider’s Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

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

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

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

Annual Resource Price Adder:

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

Annual Revenue Rate:

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff,

Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Demand Resource Constraint:

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base

Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Resource:

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

Base Day-ahead Scheduling Reserves Requirement:

~~“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.~~

Base Load Generation Resource

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Economic Load Response Participant Resource~~Demand Resource~~:

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

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

“Black Start Service” shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

“Border Yearly Charge” shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

“Breach” shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

“Breaching Party” shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

“Business Day” shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

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

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – C-D

Canadian Guaranty:

“Canadian Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

“Cancellation Costs” shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

“Capacity” shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

“Capacity Export Transmission Customer” shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

“Capacity Import Limit” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

“Capacity Interconnection Rights” shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

“Capacity Performance Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

“Capacity Resource with State Subsidy” shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

Capacity Resource Clearing Price:

“Capacity Resource Clearing Price” shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

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

Capacity Transmission Injection Rights:

“Capacity Transmission Injection Rights” shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

“Charge Economic Maximum Megawatts” shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

“Charge Economic Minimum Megawatts” shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

“Charge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

“Charge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cleared Capacity Resource with State Subsidy:

“Cleared Capacity Resource with State Subsidy” shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting

engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

“Collateral” shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. “Collateral” shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

“Collateral Call” shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Commencement Date:

“Commencement Date” shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The “Committed Offer” shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

“Completed Application” shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Composite Energy Offer:

“Composite Energy Offer” for generation resources shall mean the sum (in \$/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in \$/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

Conditional Incremental Auction:

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

Conditioned State Support:

“Conditioned State Support” shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where “conditioned on clearing in any RPM Auction” refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

“CONE Area” shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

“Confidential Information” shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through

inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

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

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

“Contingent Facilities” shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request’s costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

“Controllable A.C. Merchant Transmission Facilities” shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

Cost of New Entry:

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

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not

be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

Credit Affiliate:

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

"Credit Available for Export Transactions" shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable

Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

“Curtailment Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

“Customer Interconnection Facilities” shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer’s side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

“Daily Deficiency Rate” shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

~~Day-ahead Scheduling Reserves:~~

~~“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the ReliabilityFirst Corporation and SERC.~~

~~Day-ahead Scheduling Reserves Market:~~

~~“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.~~

~~Day-ahead Scheduling Reserves Requirement:~~

~~“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.~~

~~Day-ahead Scheduling Reserves Resources:~~

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

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

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

Deactivation:

“Deactivation” shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

“Deactivation Avoidable Cost Credit” shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, Part V, section 115 .

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

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

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or (“DR Factor”) shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

“Designated Agent” shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

“Designated Entity” shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

“Direct Assignment Facilities” shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an

unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

“Discharge Economic Maximum Megawatts” shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

“Discharge Economic Minimum Megawatts” shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

“Discharge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate:

“Discharge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

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

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant

to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

“Dynamic Transfer” shall have the same meaning provided in the Operating Agreement.

Definitions – E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:

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

Electrical Distance:

“Electrical Distance” shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

“Eligible Customer” shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency Action:

“Emergency Action” shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

Emergency Condition:

“Emergency Condition” shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

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

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

“Energy Resource” shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

“Energy Settlement Area” shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

“Energy Transmission Injection Rights” shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

“Entity Providing Supply Services to Default Retail Service Provider” shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

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

Event of Default:

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Exercise of Buyer-Side Market Power:

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

“Export Nodal Reference Price” at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

“Export Transaction” shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

“Export Transaction Price Factor” for a prospective time interval shall be the greater of (i) PJM’s forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction’s dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

“Export Transaction Screening” shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Summer Demand Resource:

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

Extended Summer Resource Price Adder:

“Extended Summer Resource Price Adder” shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

“Extended 30-minute Reserve Requirement” shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

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

External Resource:

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

Facilities Study:

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

“Financial Close” shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized

certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

“Financial Default” shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall mean Transmission Service under the Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

“Firm Transmission Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

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

Foreign Guaranty:

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

“Forward Hourly LMPs” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, “FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum

net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

“FTR Participant” shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM’s FTR market.

FTR Portfolio Auction Value:

“FTR Portfolio Auction Value” shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offers for a generation resource.

Full Notice to Proceed:

“Full Notice to Proceed” shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – L – M – N

Legacy Policy:

“Legacy Policy” shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will

not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner’s system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

“Load Interest” shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

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

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

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

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, or Tier 2 Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

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

Locational Deliverability Area Reliability Requirement:

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

Locational Price Adder:

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

Locational Reliability Charge:

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

Locational UCAP:

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

Locational UCAP Seller:

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

Long-lead Project:

“Long-lead Project” shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

“Marginal Value” shall mean the incremental change in system dispatch costs, measured as a \$/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

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

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

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

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

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

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

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

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any

Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment

T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

“Minimum Extended Summer Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

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

Minimum Participation Requirements:

“Minimum Participation Requirements” shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

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

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be

formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria

and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

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

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Services Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

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

Nominated Energy Efficiency Value:

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

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

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

Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

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

Normal Minimum Generation:

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

Definitions – O – P - Q

Obligation:

“Obligation” shall mean all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Tariff, Part II and Tariff, Part III), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for capacity purchases within the PJM capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Offer Data:

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

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

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

On-Site Generators:

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

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

“Open Access Same-Time Information System,” “PJM Open Access Same-Time Information System” or “OASIS” shall mean the electronic communication and information system and

standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve Demand Curve:

"Operating Reserve Demand Curve" shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement ~~and the value placed on maintaining that megawatt level of reserve, expressed in \$/MWh.~~

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy

from the external Generation Capacity Resource to loads in the PJM Region in a manner comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

“Opportunity Cost” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

OPSI Advisory Committee:

“OPSI Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

“Option to Build” shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

“Optional Interconnection Study” shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

“Optional Interconnection Study Agreement” shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

“Part I” shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

“Part II” shall mean Tariff, Part II, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

“Part III” shall mean Tariff, Part III, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

“Part IV” shall mean Tariff, Part IV, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

“Part V” shall mean Tariff, Part V, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

“Part VI” shall mean Tariff, Part VI, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

“Participant” shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer.

Parties:

“Parties” shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

“Peak-Hour Dispatch” shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete

start and shutdown cycle), plus 10% of such costs *only for the 2022/2023 Delivery Year*, for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate, plus 10% of such costs *only for the 2022/2023 Delivery Year*, under the same conditions as described above for the Day-ahead Energy Market.

Peak Market Activity:

“Peak Market Activity” shall mean a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of Tariff, Attachment Q, section VII.A. Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

Peak Season:

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

Percentage Internal Resources Required:

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

Performance Assessment Interval:

“Performance Assessment Interval” shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September.

Permissible Technological Advancement:

“Permissible Technological Advancement” shall mean a proposed technological change such as an advancement to turbines, inverters, plant supervisory controls or other similar advancements to the technology proposed in the Interconnection Request that is submitted to the Transmission Provider no later than the return of an executed Facilities Study Agreement (or, if a Facilities Study is not required, prior to the return of an executed Interconnection Service Agreement). Provided such change may not: (i) increase the capability of the Generating Facility as specified in the original Interconnection Request; (ii) represent a different fuel type from the original Interconnection Request; or (iii) cause any material adverse impact(s) on the Transmission

System with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response. If the proposed technological advancement is a Permissible Technological Advancement, no additional study will be necessary and the proposed technological advancement will not be considered a Material Modification.

PJM:

“PJM” shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

“PJM Administrative Service” shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

“PJM Entities” shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM’s officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

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

PJM Interchange Energy Market:

“PJM Interchange Energy Market” shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

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

PJM Interchange Import:

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

PJM Liaison:

“PJM Liaison” shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

“PJM Management” shall mean the officers, executives, supervisors and employee managers of PJM.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Markets:

“PJM Markets” shall mean the PJM Interchange Energy Market, capacity markets, including the RPM auctions, and any other market operated by PJM, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions, Financial Transmission Rights

transactions, or transactions in any other market operated under the Agreements within the PJM Region, wherein Market Participants may incur Obligations to PJM and/or PJM Settlement.

PJM Market Rules:

“PJM Market Rules” shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

“PJM Net Assets” shall mean the total assets per PJM’s consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

“PJM Region” shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:

“PJM Regional Practices Document” shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to RAA, Schedule 4.1, as approved by the PJM Board.

PJM Region Peak Load Forecast:

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

PJM Region Reliability Requirement:

“PJM Region Reliability Requirement” shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast,

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

PJMSettlement:

“PJM Settlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” “OATT,” or “PJM Open Access Transmission Tariff” shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

“Plan” shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

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

Planned External Financed Generation Capacity Resource:

“Planned External Financed Generation Capacity Resource” shall mean a Planned External Generation Capacity Resource that, prior to August 7, 2015, has an effective agreement that is the equivalent of an Interconnection Service Agreement, has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close, and has secured at least 50 percent of the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Planned External Generation Capacity Resource:

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

Planned Financed Generation Capacity Resource:

“Planned Financed Generation Capacity Resource” shall mean a Planned Generation Capacity Resource that, prior to August 7, 2015, has an effective Interconnection Service Agreement and has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close.

Planned Generation Capacity Resource:

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

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Planning Period Balance:

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

Planning Period Quarter:

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

Point(s) of Delivery:

“Point(s) of Delivery” shall mean the point(s) on the Transmission Provider’s Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

“Point of Interconnection” shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

“Point(s) of Receipt” shall mean point(s) of interconnection on the Transmission Provider’s Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

“Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

“Power Purchaser” shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

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

PRD Provider:

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

PRD Reservation Price:

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

PRD Substation:

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

Pre-Confirmed Application:

“Pre-Confirmed Application” shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

“Pre-Emergency Load Response Program” shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Pre-Expansion PJM Zones:

“Pre-Expansion PJM Zones” shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC (“MAIT”) (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

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

Primary Reserve:

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

Primary Reserve Alert

“Primary Reserve Alert” shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals~~demand for Primary Reserves in a Reserve Zone or Reserve Sub-zone, as defined by the Operating Reserve Demand Curve for Primary Reserve~~. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Principal:

“Principal” shall mean (i) the chief executive officer or senior manager that controls or directs strategy for the Participant, (ii) the chief legal officer or general counsel, (iii) the chief financial officer or senior manager that controls or directs the financial affairs and investments of the Participant, (iv) the chief risk officer or senior manager responsible for managing commodity and derivatives market risks, and (v) the officer or senior manager responsible for or to be responsible for transactions in the applicable PJM Markets. If, due to the Participant’s business enterprise, structure or otherwise, the functions attributed to any of such Principals are performed by an individual or entity separate from the Participant (such as a risk management department in an affiliate, or a director or manager at an entity that controls or invests in the Participant), then for that Participant the term Principal shall mean that individual, or the senior officer or manager of that entity, that performs such function.

Prior CIL Exception External Resource:

“Prior CIL Exception External Resource” shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM

Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

“Project Financing” shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer’s obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

“Project Finance Entity” shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer’s obligations under the corresponding power purchase agreement.

Projected EAS Dispatch:

“Projected EAS Dispatch” shall mean, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource’s offer and operating parameters. For combustion turbine units only, the cost-based energy offer will include a 10 percent adder *only for the 2022/2023 Delivery Year*.

Projected PJM Market Revenues:

“Projected PJM Market Revenues” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Provisional Interconnection Service:

“Provisional Interconnection Service” shall mean interconnection service provided by Transmission Provider associated with interconnecting the Interconnection Customer’s Generating Facility to Transmission Provider’s Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interconnection Service Agreement and, if applicable, the Tariff.

Pseudo-Tie:

“Pseudo-Tie” shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

“Public Policy Objectives” shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

“Public Policy Requirements” shall have the same meaning provided in the Operating Agreement.

Qualifying Transmission Upgrade:

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

Queue Position:

“Queue Position” shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

Definitions – R - S

Ramping Capability:

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

Real-time Congestion Price:

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

Real-time Loss Price:

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

Real-time Energy Market:

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

Real-time Offer:

“Real-time Offer” shall mean a new offer or an update to a Market Seller’s existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

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

Real-time Settlement Interval:

“Real-time Settlement Interval” shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

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

Reasonable Efforts:

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

Receiving Party:

“Receiving Party” shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

“Referral” shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

“Reference Resource” shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh.

Regional Entity:

“Regional Entity” shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

“Regional Transmission Expansion Plan” shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

“Regional Transmission Group” or “RTG” shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and

decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

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

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

“Reliability Assurance Agreement” or “PJM Reliability Assurance Agreement” shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

“Reliability Pricing Model Auction” or “RPM Auction” shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

“Regional Transmission Enhancements” shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B (“Appendix B Agreement”) designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

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

Reserve Penalty Factor:

“Reserve Penalty Factor” shall mean the cost, in \$/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

“Reserve Sub-zone” shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

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

Residual Auction Revenue Rights:

“Residual Auction Revenue Rights” shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

“Residual Metered Load” shall mean all load remaining in an electric distribution company’s fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource Substitution Charge:

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

Revenue Data for Settlements:

“Revenue Data for Settlements” shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

“RPM Seller Credit” shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

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

Schedule of Work:

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

Scope of Work:

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

Seasonal Capacity Performance Resource:

“Seasonal Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Reserve:

“Secondary Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand

can be reduced within 30 minutes (less the capability of such resources to provide Primary Reserve), from the request of the Office of the Interconnection, regardless of whether the equipment providing the reserve is electrically synchronized to the Transmission System or not.

Secondary Systems:

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

Second Incremental Auction:

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

Security:

“Security” shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer’s responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

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

Self-Supply Entity:

“Self-Supply Entity” shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where “vertically integrated utility” means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts;

“single customer entity” means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and “public power entity” means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

“Self-Supply Seller” shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where “vertically integrated utility” means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and “public power entity” means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

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

Service Agreement:

“Service Agreement” shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

“Service Commencement Date” shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

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

“Short-Term Firm Point-To-Point Transmission Service” shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

“Short-term Project” shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

“Short-Term Resource Procurement Target” shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:

“Short-Term Resource Procurement Target Applicable Share” shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

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

Small Commercial Customer:

“Small Commercial Customer,” as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a “small commercial customer” under the terms of the applicable RERRA’s program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

“Small Generation Resource” shall mean an Interconnection Customer’s device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer’s Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

“Small Inverter Facility” shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

“Small Inverter ISA” shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

“Special Member” shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

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

Spot Market Energy:

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

“Start Additional Labor Costs” shall mean additional labor costs for startup required above normal station manning levels.

Start-Up Costs:

“Start-Up Costs” shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

“State” shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

“State Commission” shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

“State Subsidy” shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

- (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or
- (2) will support the construction, development, or operation of a new or existing Capacity Resource; or
- (3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity’s obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing

herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

- (i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);
- (ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and
- (iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State of Charge:

“State of Charge” shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using minimum and maximum charge and discharge limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant's obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

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

Sub-Annual Resource Constraint:

“Sub-Annual Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

“Sub-Annual Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

“Sub-Annual Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery

Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

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

Sub-meter:

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

“Summer-Period Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

“Surplus Interconnection Customer” shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

“Surplus Interconnection Request” shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

“Surplus Interconnection Service” shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service

is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

“Switching and Tagging Rules” shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

“Synchronized Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or [Economic Load Response Participant](#) ~~Demand-R~~ resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

“Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources and/or [Economic Load Response Participant](#) ~~Demand-R~~ resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. [This requirement can only be satisfied by Synchronized Reserve resources.](#)

System Condition:

“System Condition” shall mean a specified condition on the Transmission Provider’s system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer’s Service Agreement.

System Energy Price:

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of

energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

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

System Protection Facilities:

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

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the

relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric

distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated

hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
- b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
- c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
- d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the

matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

- b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

(“Pilot Period”). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Economic Load Response Participant resource ~~Demand-Resource~~ Provision of Synchronized Reserve or ~~Day-ahead Scheduling~~ Secondary Reserves.

(a) A Batch Load Economic Load Response Participant resource ~~Demand-Resource~~ may provide Synchronized Reserve or ~~Day-ahead Scheduling~~ Secondary Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Economic Load Response Participant resource ~~Demand-Resource~~, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of “Batch Load Economic Load Response Participant resource ~~Demand-Resource~~” pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Economic Load Response Participant resource ~~Demand-Resource~~.

~~———— (b) ——— Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection’s filing and thereafter if approved or accepted by the Commission.~~

(~~e~~b) A Batch Load Economic Load Response Participant resource ~~Demand-Resource~~ that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to

provide ~~Secondary Day-ahead Scheduling~~ Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of ~~Secondary Day-ahead Scheduling~~ Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load ~~Economic Load Response Participant resource Demand Resource~~ that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of ~~Secondary Day-ahead Scheduling~~ Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of ~~Secondary Day-ahead Scheduling~~ Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide ~~Secondary Day-ahead Scheduling~~ Reserves to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the ~~Secondary Day-Ahead Scheduling~~ Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-

Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;

v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each End-Use Customer site must meet the requirements for market participation by an [Economic Load Response Participant](#) ~~demand~~-resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by an [Economic Load Response Participant](#) ~~demand~~-resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

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

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

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

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, [Economic Load Response Participant resources](#)~~Demand Resources~~, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be

separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Operating Agreement, s~~Section 14 of this Agreement~~, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

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

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the applicable interval Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in the applicable interval, shall

be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues from there shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in [Operating Agreement, Schedule 1, s](#)~~Section 3 to this Schedule~~. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

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

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

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

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

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

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

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not Dynamic Transfers pursuant to [Operating Agreement, Schedule 1, s](#)Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such

resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

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

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), “net output” of a generation facility during any month means the facility’s gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility’s or a Market Seller’s monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as “remote self-supply of Station Power”), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility’s negative net output from Market Seller’s generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A; Tariff, Schedule 2; Tariff, Schedule 3; Tariff Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station

Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

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

(iv) The Office of the Interconnection is not responsible for determining Relevant Electric Retail Regulatory Authority-jurisdictional retail rates, and the monthly netting provision in section 1.7.10(d)(i) above does not determine whether a retail sale of station power has occurred in a month. Furthermore, notwithstanding any provision of subsection (d)(i) or (d)(ii) to the contrary, any net output determined for a Market Seller for Station Power purposes shall, as more fully set forth in the PJM manuals, take account of MWh values submitted to the Office of the Interconnection via its metering reporting systems by the Market Seller or the applicable Electric Distribution Company designated to make such submission, that reflect the Market Seller's purchase of energy at retail to meet its Station Power needs.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after

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

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

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

1.7.14 PJM Manuals.

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

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 [Reserved.]

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or [Economic Load Response Participant resources](#) ~~demand-resources~~ located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

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

(c) The Regulation range of a generation unit or [Economic Load Response Participant resource](#) ~~demand-resource~~ shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

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

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator. [Market Sellers must specify a ramping rate in the Offer Data that is an accurate representation of the resource's capabilities given the confines of the PJM software.](#)

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from ~~non-emergency~~ generation resources and/or [Economic Load Response Participant resources](#) ~~Demand Resources~~ located within the metered boundaries of the PJM Region. [A resource is not eligible to provide Synchronized Reserve if its entire output has been designated as emergency energy or if the resource is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the](#)

resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. ~~All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Tariff, Attachment K-Appendix, section 2.5(d) and the parallel provision of Operating Agreement, Schedule 1, section 2.5(d), all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves.~~ Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary Reserve Requirement and Synchronized Reserve Requirement objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

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

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Non-Synchronized Reserve if (i) its Resources, the entire output of which has been designated as emergency energy, (ii) it is not and resources that aren't available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection are not eligible to provide Non-Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve ~~objective~~ Requirement for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

~~(d) The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can~~

~~demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability of a generation resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.~~

~~(e) — All Non-Synchronized Reserve offers shall be for \$0.00/MWh.~~

1.7.19A.02 Secondary Reserve.

(a) Secondary Reserve can be supplied from synchronized and non-synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region, as specified in the PJM Manuals. A resource is not eligible to provide Secondary Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Secondary Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers and Market Sellers offering Secondary Reserve shall comply with applicable standards and requirements for Secondary Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone, as applicable, an amount of Secondary Reserve such that the sum of the Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve meets the respective 30-minute Reserve Requirement for each such Reserve Zone and Reserve Sub-zone, as applicable, and as specified in the PJM Manuals. In accordance with the PJM Manuals, the Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the 30-minute Reserve Requirement in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Secondary Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 30-

minute period, minus the increase in energy output or load reduction achievable within a continuous 10-minute period.

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

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

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

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

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non- Synchronized Reserve, or Secondary ~~Day-ahead Scheduling~~ Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

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

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

1.7.20 Communication and Operating Requirements.

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

(b) Market Sellers selling from generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ within the PJM Region shall: report to the Office of the Interconnection sources of energy and Economic Load Response Participant resources ~~Demand Resources~~ available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Economic Load Response Participant resources ~~Demand Resources~~ that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection

bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from [Economic Load Response Participant resources](#)~~Demand Resources~~; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and [Economic Load Response Participant resources](#)~~Demand Resources~~ are operated with control equipment functioning as specified in the PJM Manuals.

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

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

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

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.10 Scheduling.

1.10.1 General.

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

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

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

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

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses

the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of [Tariff, Attachment K-Appendix, Section 1.13](#) ~~of this Schedule 1 of this Agreement~~. Scheduling shall be conducted as specified in [Section 1.10.1A](#) below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with [Tariff, Attachment K-Appendix, Sections 3.2.3 and Tariff, Attachment K-Appendix, section 6.6](#) ~~hereof~~.

1.10.1A Day-ahead [and Real-time](#) Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

Substation basis, and shall specify the maximum time period required to implement load reductions.

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed ~~/\$2,000~~/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-~~T~~ime Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to \$2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Tariff, Attachment K-Appendix, S~~ection~~ 1.12; and

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

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to

Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to \$2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this ~~S~~section 1.10.1A(d), ~~S~~section 1.10.9B below, Operating Agreement, Schedule 2 ~~of the Operating Agreement~~, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on

either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

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

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

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

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or ~~Demand~~Economic Load Response Participant Rresource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

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

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; ~~and~~ (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for ~~Demand~~Economic Load Response Participant Rresources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2)

shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

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

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

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour;

ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to [Tariff, Attachment DD-1](#), ~~Section A.2 of Attachment DD-1 of the Tariff~~ and the parallel provision of [RAA](#), Schedule 6 ~~of the RAA~~, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;

b) an approved 60 minute lead time, pursuant to [Tariff, Attachment DD-1, Section A.2](#) ~~of Attachment DD-1 of the Tariff~~ and the parallel provision of [RAA, Schedule 6](#) ~~of the RAA~~, \$1,000/megawatt hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to [Tariff, Attachment DD-1, Section A.2](#) ~~of Attachment DD-1 of the Tariff~~ and the parallel provisions of [RAA, Schedule 6](#) ~~of the RAA~~, \$1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

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

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such

Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with [Tariff, Attachment K-Appendix, sections 3.2.3 and Tariff, Attachment K-Appendix, section 6.6 hereof](#).

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

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

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

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a

Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of

implementation of this rule the expected value of the penalty shall be \$0.02/MWh, and for the period from the second month after implementation through the second January 1 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available

Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

~~(1) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that~~Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts,~~the price of the offer in dollars per megawatt hour,~~and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer~~and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs.~~ Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.~~The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.~~

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, ~~start-up~~shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

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

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied,

offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available

Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating

configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for \$0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

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

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = -greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether

the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in [Section 1.10.1A above](#). Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

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

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

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

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

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

1.10.3 Self-scheduled Resources.

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

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

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

~~(e)~~ For energy, Hhydropower units, excluding pumped storage units, may only be self-scheduled.

~~(f)~~ g A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

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

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

must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

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

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

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

1.10.6 External Market Buyers.

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

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

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

1.10.7 Bilateral Transactions.

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

1.10.8 Office of the Interconnection Responsibilities.

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

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection

in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in ~~S~~ection 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to [Tariff, Attachment K-Appendix, S](#)ection 3.3A ~~of this Schedule~~. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to [Tariff, Attachment K-Appendix, S](#)ections 2.4 and [Tariff, Attachment K-Appendix, section 2.5](#) ~~hereof~~.

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

[Services Markets](#), and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the ~~Day-ahead Scheduling Reserve Market and~~ Day-ahead Energy Market [and Day-ahead Ancillary Services Markets](#). After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the ~~Ancillary Services Markets and~~ Real-time Energy Market [and Real-time Ancillary Services Markets](#), and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the ~~Day-ahead Scheduling Reserve Market and the~~ Day-ahead Energy Market [and Day-ahead Ancillary Services Markets](#). *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the ~~Ancillary Services Markets, Day-ahead Energy Market, and~~ Real-time Energy Market, and [Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets](#) ~~no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market~~. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

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

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A-~~of~~ ~~this Schedule~~ below:

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

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

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

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

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this sSection 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; ~~and~~ (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs;

(2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (69) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

(c) For ~~Demand~~Economic Load Response Participant ~~R~~resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11 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 Economic Load Response Participant resources ~~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 Operating Agreement, Schedule 1, sSection 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 Economic Load Response Participant resources ~~Demand Resources~~ as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources ~~Demand Resources~~ offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant resources ~~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 [Economic Load Response Participant resources](#) ~~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 [Economic Load Response Participant resources](#) ~~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~~ [energy](#) 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 [Economic Load Response Participant resources](#) ~~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 [Operating Agreement, Schedule 1, s](#) ~~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 [available](#) either pool-scheduled or self-scheduled generation resources and/or [Economic Load Response Participant resources](#) ~~Demand Resources~~ as needed to meet the Synchronized Reserve ~~R~~ requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. [The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market.](#) Resources ~~offering to sell Synchronized Reserve~~ shall be ~~selected~~ [cleared](#) to provide Synchronized Reserve on the basis of each generation resource's and/or [Economic Load Response Participant resource](#) ~~Demand Resource~~'s Synchronized Reserve offer and the ~~estimated unit specific opportunity cost of the resource~~ [product substitution cost of providing Synchronized Reserve, energy and any other product the resource is capable of providing,](#) and in accordance with the Office of the Interconnection's obligation to [jointly procure and](#) minimize the total [production](#) cost of energy, [and of meeting the](#) ~~Operating Reserves,~~

Synchronized Reserve [Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement.](#) However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product. ~~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) The Office of the Interconnection shall dispatch generation resources and/or [Economic Load Response Participant resources](#) ~~Demand Resources~~ for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or [Economic Load Response Participant resources](#) ~~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~~ [energy](#) in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources 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 [Operating Agreement, Schedule 1, s](#)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 Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Resources providing Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Non-Synchronized Reserve Market and the Real-time Non-Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Non-Synchronized Reserve Market~~Market Buyers~~. Resources eligible to sell Non-Synchronized Reserve shall be ~~selected~~ cleared to provide Non-Synchronized Reserve on the basis of each ~~generation~~ resource's product substitution cost between~~estimated unit-specific opportunity cost of the resource~~ providing Non-Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement~~, 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~~ energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJM Settlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJM Settlement shall not be a contracting party to bilateral transactions between Market Participants.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each

Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

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

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Tariff, Attachment K-Appendix, section 2.4. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the applicable reserve requirements. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any monitored transmission constraints that may exist.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Tariff, Attachment K-Appendix, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.

(c) In performing the Real-time Price calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as described in Tariff, Attachment K-Appendix, section 2.4 as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative), including Transmission Constraint Penalty Factors, associated with increasing the output of a generation resource or decreasing the consumption by a Demand

Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(d) During the Operating Day, the calculation set forth in Tariff, Attachment K-Appendix, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

2.5.1 Declaration of Shortage Pricing

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a [30-minute Reserve shortage](#), a Primary Reserve shortage and/or a Synchronized Reserve shortage for the purposes of declaring shortage pricing as further described in the PJM Manuals. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, Real-time Prices shall be calculated as described in Tariff, Attachment K-Appendix, section 2.5 and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When the Real-time Price software determines that a [30-minute Reserve shortage](#), a Primary Reserve shortage and/or a Synchronized Reserve shortage exists, whereby the reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the Office of Interconnection shall implement shortage pricing. During shortage pricing, the Real-time Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement [consistent with the determination of the clearing price for each reserve product](#), and the components of Locational Marginal Prices referenced in Tariff, Attachment K-Appendix, section 2.5 above shall be calculated as described below. Shortage pricing shall exist until the Real-time Price software program is able to meet the specified reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect.

(b) If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the [30-minute Reserve Requirement](#), the Primary Reserve Requirement, and ~~the Reserve Penalty Factor for the Synchronized Reserve Requirement~~ are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, the [Secondary Reserve Market Clearing Price](#), and Locational Marginal Price, as applicable [and](#)

consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minute Reserve Requirement, ~~for the Primary Reserve Requirement~~, and ~~the Reserve Penalty Factor for the Synchronized Reserve Requirement~~ will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and ~~the Reserve Penalty Factor for the Synchronized Reserve Requirement~~ are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and ~~the Reserve Penalty Factor for the Synchronized Reserve Requirement~~ will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Manual Load Dump Action has been terminated.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Tariff, Attachment K-Appendix, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, ~~Day-ahead Scheduling Reserve~~ offers for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. ~~The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Day-ahead Price at that bus.~~ The day-ahead Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource

constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

(b) The Office of the Interconnection shall use its day-ahead market clearing software to forecast if the Office of the Interconnection will experience a shortage of the 30-minute Reserve Requirement, Extended 30-minute Reserve Requirement, the Primary Reserve Requirement, Extended Primary Reserve Requirement, the Synchronized Reserve Requirement, and/or the Extended Synchronized Reserve Requirement, as further described in the PJM Manuals. If the day-ahead market clearing software forecasts that a shortage of any of the reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Day-ahead Locational Marginal Prices consistent with the determination of the clearing price for each reserve product. Shortage pricing shall exist until the day-ahead market clearing software is able to meet the specified reserve requirements.

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with [Tariff, Attachment K-Appendix, s](#)~~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 [Tariff, Attachment K-Appendix](#), 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 below](#), 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 below~~ shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in [Tariff, Attachment K-Appendix](#), section 1.10.1A(e) ~~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 [Economic Load Response Participant resources](#) ~~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 [Economic Load Response Participant resources](#) ~~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:

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

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 [Tariff, Attachment K-Appendix](#), 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 ~~S~~sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 ~~of Schedule 1 of this Agreement~~ below does not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Day-ahead Scheduling ~~Reserves Requirements~~, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market ~~Day-ahead Scheduling Reserves Requirement~~. PJM Settlement 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 ~~s~~Section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources ~~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 [sSection 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 [sSection 3.2.3\(b\)](#) plus any unallocated charges from [sSection 3.2.3\(h\)](#) and [Tariff, Attachment K-Appendix, section 5.1.7](#), and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves 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 [Tariff, Attachment K-Appendix, sSection 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 [Tariff, 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 Economic Load Response Participant resources~~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 Economic Load Response Participant resources~~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 Economic Load Response Participant resources~~Demand Resources~~) costs for generation resources.

Except as provided in sSection 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below 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 sSection 3.2.3B, and the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve 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~~Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and ~~Day-ahead Scheduling~~Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, sSection 1.10.3-(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC D 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 [Tariff, Attachment K-Appendix, S](#)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 ~~LOC 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 [Tariff, Attachment K-Appendix, s](#)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 [Tariff, 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 [Tariff, Attachment K-Appendix](#), 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 [Tariff, Attachment K-Appendix](#), 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 [Tariff](#), 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 below](#), 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, [Secondary Reserve](#), or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, [Secondary Reserve](#), or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in [s](#)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, [Secondary Reserve](#), or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, [Secondary Reserve](#), or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (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 [Tariff, Attachment K-Appendix, s](#)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 [s](#)Section 3.2.3.(b) or [s](#)Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as “MaxGen

Conditions”). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with [Operating Agreement, Schedule 2](#) ~~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 [Tariff, Attachment K-Appendix, Section 1.10](#) for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by [Tariff, Attachment K-Appendix, Section 1.9.7\(b\)](#); provided, however, that the Market Seller must return to compliance with [Tariff, Attachment K-Appendix, Section 1.9.7\(b\)](#) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller’s lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. 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:

$$Ramp_Request_t = (Dispatch_target_{t-1} - AOutput_{t-1}) / (LTime_{t-1})$$

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

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. LTime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes

5. $RL_Desired = \text{Ramp-limited desired MW}$

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~~ [Response Participant 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 [Tariff, Attachment K-Appendix](#), 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 [Tariff, Attachment K-Appendix](#), ~~s~~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 [Tariff](#), 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 exceeds the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges 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 [Tariff, Attachment K-Appendix, sSection 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 [sSection 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 [Tariff, Schedule 6A of the PJM Tariff](#), in excess of the regional adder rates calculated pursuant to [Tariff, Attachment K-Appendix, sSection 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 [sSection 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, [Operating Agreement, 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, Operating Agreement, 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 Tariff, Attachment K-Appendix, 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's ~~with an~~ hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below ~~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 and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market ~~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 equal to the product of the higher of (i) the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide, 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.

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the

event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below. ~~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) [Reserved for future use] ~~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) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

(d)(ii) For the Real-time Synchronized Reserve Market, ~~t~~ 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~~price of serving the next increment of demand for Synchronized Reserve in ~~each a~~ Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using ~~inclusive of~~ Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute. ~~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 Real-time Synchronized Reserve Market ~~5-minute~~ Clearing ~~p~~Price shall be the sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement for ~~that each~~ Reserve Zone or Reserve Sub-zone to which it can contribute.

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

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

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

(e) (i) For ~~each Real-time Settlement Interval and for~~ determining the ~~5-minute~~ Synchronized Reserve Market ~~C~~elaring ~~P~~price in each hour of the Day-ahead Synchronized Reserve Market, the estimated ~~unit~~resource-specific opportunity cost for a generation resource or

Economic Load Response Participant resource shall ~~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~~ or Economic Load Response Participant resource ~~bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch Synchronized Reserve set-point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation~~ or Economic Load Participant resource ~~bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.~~

~~However, t~~ The opportunity costs for a Demand Resource shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero

shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Tier-2 Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the ~~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 operating hour 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:

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

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 =~~ A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

~~C =~~ B = The deviation of the generation resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment follow the Office of the Interconnection's signals and instructions from the generation resource's energy expected output or load reduction level if it had been dispatched assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

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

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, capped at the amount of Synchronized Reserve the resource responded during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A] plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time

Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B + C + D) - (E + F + G + H)$$

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

~~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) ~~[Reserved for future use] 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) ~~For each operating hour, the sum of the Any amounts credited for Tier 2 Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above 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 real-time purchases of Synchronized Reserve in megawatt-hours during that hour.~~

(i) ~~[Reserved for future use] 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) In the event a generation resource or Economic Load Response Participant Resource ~~Demand Resource~~ that either has been assigned by the Office of the Interconnection or self-scheduled to provide ~~Tier 2~~ Synchronized Reserve in real-time fails to provide the assigned or self-scheduled amount of ~~Tier 2~~ Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be charged at the Real-time ~~credited for Tier 2~~ Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource, capacity in the excess of amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled ~~Tier 2~~ Synchronized Reserve real-time on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for ~~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 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 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 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 resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time 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 retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts ~~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 an Economic Load Response Participant resource ~~Demand Resource~~, except for Batch Load Economic Load Response Participant resource ~~Demand Resources~~ covered by section 3.2.3A(1), is the difference between the generation resource's output or the Economic Load Response Participant resource ~~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 Economic Load Response Participant resource ~~Demand Resource~~ consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource ~~Demand Resource~~ consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource ~~Demand Resource~~'s consumption 10 minutes after the event is

defined as the greatest generator resource output or lowest [Economic Load Response Participant resource](#) ~~Demand-Resource~~ consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an [Economic Load Response Participant resource](#) ~~Demand-Resource~~ will be reduced by the amount the megawatt consumption of the [Economic Load Response Participant resource](#) ~~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 [Economic Load Response Participant resource](#) ~~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 [Economic Load Response Participant resource](#) ~~Demand-Resource~~'s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load [Economic Load Response Participant resource](#) ~~Demand-Resource~~'s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load [Economic Load Response Participant resource](#) ~~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's ~~with an~~ hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below ~~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) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows: ~~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.~~

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating

Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

(eii) For the Real-time Non-Synchronized Reserve Market, ~~The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. 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 price of serving the next increment of demand for Primary Reserve procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each a Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.~~ 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 Real-time Non-Synchronized Reserve Market 5-minute Clearing Price shall be sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement and the Reserve Penalty Factor for the Primary Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute that Reserve Zone or Reserve Sub-zone.

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

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

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

(d) (i) For ~~each Real-time Settlement Interval and for~~ determining the ~~5-minute~~ Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, 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:~~ zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$\text{(zero)} - (A + B + C + D)$$

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

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

~~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) [Reserved for future use] ~~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) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above ~~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 real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

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

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

3.2.3A.01 ~~Day-ahead Scheduling~~Secondary Reserves.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.~~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. PJM Settlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJM Settlement 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) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below. ~~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 (e) of this section.~~

(c) [Reserved for future use] ~~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) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Tariff, Attachment K-

Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirements for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be \$300/MWh.

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

(c) ~~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.~~(i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric

resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

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

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit

order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

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

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero,

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B) - (C + D + E + F)$$

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing Secondary Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch

algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output 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 [sSections 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 [Tariff, Attachment K-Appendix, sSection 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 [Tariff, Attachment K-Appendix, sSection 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 [sSection 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 [sSection 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 [Tariff, Attachment K-Appendix, sSection 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 [Tariff, Attachment K-Appendix, s](#)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 [s](#)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-applicable~~ Synchronized Reserve ~~R~~ 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 ~~s~~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 Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the 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 [Tariff, Attachment K-Appendix, s](#)~~Section 5-of this Schedule.~~

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in [Tariff, Attachment K-Appendix, s](#)~~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 ~~\$850/MWh~~~~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 [Tariff, Attachment K-Appendix, s](#)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 [Operating Agreement, s](#)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.

Sections of the
PJM Operating Agreement

Effective December 31, 9998

(Marked/Redline Format)

Definitions A - B

30-minute Reserve:

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

Act:

“Act” shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

“Active and Significant Business Interest” is a term that shall be used to assess the scope of a Member’s PJM membership and shall be based on a Member’s activity in the PJM RTO and/or Interchange Energy Markets. A Member’s Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member’s PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member’s public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member’s recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates’ interests within the PJM footprint.

~~Additional Day-ahead Scheduling Reserves Requirement:~~

~~“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead~~

~~Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.~~

Affected Member:

“Affected Member” shall mean a Member of PJM which as a result of its participation in PJM’s markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreement, Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Agreement,” “Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

Annual Meeting of the Members:

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

[Applicable Standards:](#)

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Associate Member:

“Associate Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Commission:

“Authorized Commission” shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

“Authorized Person” shall have the meaning set forth in Operating Agreement, section 18.17.4.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to

Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

~~Base Day-ahead Scheduling Reserves Requirement:~~

~~“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.~~

Batch Load Economic Load Response Participant Resource~~Demand Resource~~:

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

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

“Board Member” shall mean a member of the PJM Board.

Definitions C - D

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Catastrophic Force Majeure:

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

Charge Economic Maximum Megawatts:

“Charge Economic Maximum Megawatts” shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

“Charge Economic Minimum Megawatts” shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

“Charge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

“Charge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Committed Offer:

The “Committed Offer shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Compliance Monitoring and Enforcement Program:

“Compliance Monitoring and Enforcement Program” shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

Composite Energy Offer:

“Composite Energy Offer” for generation resources shall mean the sum (in \$/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in \$/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A and the PJM Manuals.

Congestion Price:

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or “Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other

transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the extent that energy serves that Member's own load.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45) Schedule A. The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C, Attachment 3, section 2.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment Service Provider:

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

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

~~Day-ahead Scheduling Reserves:~~

~~“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the ReliabilityFirst Corporation and SERC.~~

~~Day-ahead Scheduling Reserves Market:~~

~~“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.~~

~~Day-ahead Scheduling Reserves Requirement:~~

~~“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.~~

~~Day-ahead Scheduling Reserves Resources:~~

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

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

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

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default Allocation Assessment:

“Default Allocation Assessment” shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

“Demand Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Designated Entity:

“Designated Entity” shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

Direct Charging Energy:

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

“Discharge Economic Maximum Megawatts” shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

“Discharge Economic Minimum Megawatts” shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

“Discharge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate:

“Discharge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

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

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Dynamic Transfer:

“Dynamic Transfer” shall mean a Pseudo-Tie or Dynamic Schedule.

Definitions E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall mean an enhancement or expansion described in Operating Agreement, Schedule 6, section 1.5.7(b) (i) – (iii) that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

“Effective Date” shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EIDSN, Inc.:

“EIDSN, Inc.” shall mean the nonstock, nonprofit corporation, formerly known as Eastern Interconnection Data Sharing Network, Inc., or any successor thereto, that is operated primarily for the purpose of developing operating tools and the facilitation of the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among Reliability Coordinators and other relevant parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk electric system in the Eastern Interconnection.

Electric Distributor:

“Electric Distributor” shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency:

“Emergency” shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Member Committee classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Equivalent Load:

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

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

“Extended 30-minute Reserve Requirement” shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

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

External Resource:

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

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for an Operating Day.

Finance Committee:

“Finance Committee” shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offer(s) for a generation resource.

Definitions I - L

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall mean a reliability-based transmission enhancement or expansion that the Office of the Interconnection has identified to resolve a need that must be addressed within three years or less from the year the Office of the Interconnection identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3.

Inadvertent Interchange:

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

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean the cost in dollars per MWh of providing an additional MWh from a synchronized unit. It consists primarily of the cost of fuel, as determined by the unit’s incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances, tax credits, and energy market opportunity costs.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Information Request:

“Information Request” shall mean a written request, in accordance with the terms of the Operating Agreement for disclosure of confidential information pursuant to Operating Agreement, section 18.17.4.

Integer Relaxation:

“Integer Relaxation” shall mean the process by which the commitment status variable for an Eligible Fast-Start Resource is allowed to vary between zero and one, inclusive of zero and one, as further described in Operating Agreement, Schedule 1, section 2.2.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Internal Market Buyer:

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

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

LLC:

“LLC” shall mean PJM Interconnection, L.L.C., a Delaware limited liability company.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Reduction Event:

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

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Local Plan:

“Local Plan” shall include Supplemental Projects as identified by the Transmission Owners within their zone and Subregional RTEP projects developed to comply with all applicable reliability criteria, including Transmission Owners’ planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

Locational Marginal Price:

“Locational Marginal Price” or “LMP” shall mean the market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, or Tier 2 Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Long-lead Project:

“Long-lead Project” shall mean a transmission enhancement or expansion with an in-service date more than five years from the year in which, pursuant to Operating Agreement, Schedule 6,

section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Definitions M - N

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Market Buyer:

“Market Buyer” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and/or PJM Settlement in Tariff, Attachment Q, and that is otherwise able to make purchases in the PJM Interchange Energy Market.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” shall mean the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM.

Market Operations Center:

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

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, and/or an Economic Load Response Participant, except when that term is used in or pertaining to Tariff, Attachment M, Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4. “Market Participant,” when such term is used in Tariff, Attachment M, shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but

does not purchase or sell energy at wholesale. “Market Participant,” when such term is used in or pertaining to Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4, shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, an FTR Participant, a Capacity Market Buyer, or a Capacity Market Seller.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller:

“Market Seller” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and/or PJMSettlement in Tariff, Attachment Q, and that is otherwise able to make sales in the PJM Interchange Energy Market.

Maximum Emergency:

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

Maximum Generation Emergency:

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

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Operating Agreement, Schedule 4.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

Minimum Generation Emergency:

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

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM’s State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

“Multi-Driver Project” shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation, or any successor thereto.

NERC Functional Model:

“NERC Functional Model” shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Interchange Distribution Calculator:

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

NERC Reliability Standards:

“NERC Reliability Standards” shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.

NERC Rules of Procedure: “NERC Rules of Procedure” shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Network Resource:

“Network Resource” shall have the meaning specified in the PJM Tariff.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

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

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Non-Disclosure Agreement:

“Non-Disclosure Agreement” shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Operating Agreement, section, the form of which is appended to this Agreement as Operating Agreement, Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Nonincumbent Developer:

“Nonincumbent Developer” shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J.

Non-Regulatory Opportunity Cost:

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

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, 1.5A.6.

Normal Maximum Generation:

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

Normal Minimum Generation:

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

Definitions O - P

Offer Data:

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

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

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

On-Site Generators:

“On-Site Generators” shall mean generation facilities or portions of a generation facility (including Behind The Meter Generation) that (i) are not Generation Capacity Resources, (ii) are not injecting into the grid for the portion of a generation facility that participates as an Economic Load Response Participant or as a Demand Resource, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-time Information System:

“Open Access Same-Time Information System,” “PJM Open Access Same-time Information System” or “OASIS” shall mean the electronic communication system and information system and standards of conduct contained in Part 37 and Part 38 of the Commission’s regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Operating Reserve Demand Curve:

“Operating Reserve Demand Curve” shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement.

Operator-initiated Commitment:

“Operator-initiated Commitment” shall mean a commitment after the Day-ahead Energy Market and Day-ahead Scheduling Reserves Market, whether manual or automated, for a reason other than minimizing the total production costs of serving load.

Original PJM Agreement:

“Original PJM Agreement” shall mean that certain agreement between certain of the Members, originally dated September 26, 1956, and as amended and supplemented up to and including December 31, 1996, relating to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and; (ii) does not qualify for the Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer sectors.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Dispute Resolution Procedures:

“PJM Dispute Resolution Procedures” shall mean the procedures for the resolution of disputes set forth in Operating Agreement, Schedule 5.

PJM Governing Agreements:

“PJM Governing Agreements” shall mean the PJM Open Access Transmission Tariff, the Operating Agreement, the Consolidated Transmission Owners Agreement, the Reliability Assurance Agreement, or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and any of its Members.

PJM Interchange:

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

PJM Interchange Energy Market:

“PJM Interchange Energy Market” shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix.

PJM Interchange Export:

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

PJM Interchange Import:

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

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Mid-Atlantic Region:

“PJM Mid-Atlantic Region” shall mean the aggregate of the Transmission Facilities of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

PJM Region:

“PJM Region” shall mean the aggregate of the Zones within PJM as set forth in Tariff, Attachment J.

PJMSettlement:

“PJMSettlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM South Region:

“PJM South Region” shall mean the Transmission Facilities of Virginia Electric and Power Company.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” or “PJM Open Access Transmission Tariff” shall mean that certain “PJM Open Access Transmission Tariff”, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

PJM West Region:

“PJM West Region” shall mean the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Affiliate Companies; The Dayton Power and Light Company; the Duquesne Light Company; American Transmission Systems, Incorporated; Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc. and East Kentucky Power Cooperative, Inc.

Planning Period:

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

Planning Period Balance:

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

Planning Period Quarter:

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

Point-to-Point Transmission Service:

“Point-to-Point Transmission Service” shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Delivery under Tariff, Part II.

PRD Curve:

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

PRD Provider:

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

PRD Reservation Price:

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

PRD Substation:

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

Pre-Emergency Load Response Program:

“Pre-Emergency Load Response Program” shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-appendix, section 8.

President:

“President” shall have the meaning specified in Operating Agreement, section 9.2.

Price Responsive Demand:

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

Primary Reserve:

“Primary Reserve” shall mean the total reserve capability of generation resources that can be converted fully into energy or [Economic Load Response Participant resources](#) ~~Demand Resources~~ whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Alert:

“Primary Reserve Alert” shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals. [The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.](#)

Prohibited Securities:

“Prohibited Securities” shall mean the Securities of a Member, Eligible Customer, or Nonincumbent Developer, or their Affiliates, if:

(1) the primary business purpose of the Member or Eligible Customer, or their Affiliates, is to buy, sell or schedule energy, power, capacity, ancillary services or transmission services as indicated by an industry code within the “Electric Power Generation, Transmission, and Distribution” industry group under the North American Industry Classification System (“NAICS”) or otherwise determined by the Office of the Interconnection;

(2) the Nonincumbent Developer has been pre-qualified as eligible to be a Designated Entity pursuant to Operating Agreement, Schedule 6;

(3) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during its most recently completed fiscal year is equal to or greater than 0.5% of its gross revenues for the same time period; or

(4) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during the prior calendar year is equal to or greater than 3% of the total transactions for which PJMSettlement is a Counterparty pursuant to Operating Agreement, section 3.3 for the same time period.

The Office of the Interconnection shall compile and maintain a list of the Prohibited Securities publicly traded and post this list for all employees and distribute the list to the Board Members.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Pseudo-Tie:

“Pseudo-Tie shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Public Policy Objectives:

“Public Policy Objectives” shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations.

Public Policy Requirements:

“Public Policy Requirements” shall refer to policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity.

Definitions S – T

Sector Votes:

“Sector Votes” shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

“Securities” shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

“Senior Standing Committees” shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

“SERC” or “Southeastern Electric Reliability Council” shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

“Short-term Project” shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

“Special Member” shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

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

Spot Market Energy:

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Standing Committees:

“Standing Committees” shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start-Up Costs:

“Start-Up Costs” shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

“State” shall mean the District of Columbia and any State or Commonwealth of the United States.

State Certification:

“State Certification” shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State of Charge:

“State of Charge” shall mean the operating parameter that represents the quantity of physical energy stored (measured in units of megawatt-hours) in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using Charge and Discharge Economic Minimum and Maximum Megawatts limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant’s obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

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

Sub-meter:

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Subregional RTEP Project:

“Subregional RTEP Project” shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

“Supplemental Project” shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

“Synchronized Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or [Economic Load Response Participant Demand R](#)esources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

“Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources and/or [Economic Load Response Participant Demand R](#)esources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. [This requirement can only be satisfied by Synchronized Reserve resources.](#)

System:

“System” shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3 or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Party Request:

“Third Party Request” shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

“Tie Line” shall have the same meaning provided in the Open Access Transmission Tariff.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the

cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Customer:

“Transmission Customer” shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

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

Transmission Loading Relief:

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

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Operator:

“Transmission Operator” shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall mean an upgrade to a Transmission Owner’s own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages

specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the

relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric

distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated

hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
- b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
- c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
- d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the

matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

- b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

(“Pilot Period”). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Economic Load Response Participant resource ~~Demand-Resource~~ Provision of Synchronized Reserve or ~~Day-ahead Scheduling~~ Secondary Reserves.

(a) A Batch Load Economic Load Response Participant resource ~~Demand-Resource~~ may provide Synchronized Reserve or ~~Day-ahead Scheduling~~ Secondary Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Economic Load Response Participant resource ~~Demand-Resource~~, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of “Batch Load Economic Load Response Participant resource ~~Demand-Resource~~” pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Economic Load Response Participant resource ~~Demand-Resource~~.

~~———— (b) ——— Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection’s filing and thereafter if approved or accepted by the Commission.~~

(~~e~~b) A Batch Load Economic Load Response Participant resource ~~Demand-Resource~~ that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to

provide ~~Day-ahead Scheduling~~ Secondary Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of ~~Day-ahead Scheduling~~ Secondary Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Economic Load Response Participant resource Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of ~~Day-ahead Scheduling~~ Secondary Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of ~~Day-ahead Scheduling~~ Secondary Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide ~~Day-ahead Scheduling~~ Secondary Reserves to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the ~~Day-Ahead Scheduling~~ Secondary Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the

aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;

v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each End-Use Customer site must meet the requirements for market participation by an [Economic Load Response Participant](#) ~~demand~~ resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by an [Economic Load Response Participant](#) ~~demand~~ resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

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

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

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

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, [Economic Load Response Participant resources](#)~~Demand Resources~~, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with

Operating Agreement, ~~Section 14 of this Agreement~~, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

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

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ economically on the basis of least-cost, security-constrained dispatch and the prices and

operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

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

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in [Operating Agreement, Schedule 1, s](#)~~Section 3 to this Schedule~~. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

- (i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its InSchedule and ExSchedule tools.
- (ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

- (iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.
- (iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.
- (v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.
- (vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that

are not Dynamic Transfers pursuant to [Operating Agreement, Schedule 1, s](#)Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

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

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

- (i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.
- (ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market

Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A; Tariff, Schedule 2; Tariff, Schedule 3; Tariff, Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

- (iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.
- (iv) The Office of the Interconnection is not responsible for determining Relevant Electric Retail Regulatory Authority-jurisdictional retail rates, and the monthly netting provision in section 1.7.10(d)(i) above does not determine whether a retail sale of station power has occurred in a month. Furthermore, notwithstanding any provision of subsection (d)(i) or (d)(ii) to the contrary, any net output determined for a Market Seller for Station Power purposes shall, as more fully set forth in the PJM manuals, take account of MWh values submitted to the Office of the Interconnection via its metering reporting systems by the Market Seller or the applicable Electric Distribution Company designated to make such submission, that reflect the Market Seller's purchase of energy at retail to meet its Station Power needs.

1.7.11 Emergencies.

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

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

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

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

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

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed

to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 [Reserved.]

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Economic Load Response Participant resources ~~demand resources~~ located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

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

(c) The Regulation range of a generation unit or Economic Load Response Participant resource ~~demand resource~~ shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

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

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change

output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator. Market Sellers must specify a ramping rate in the Offer Data that is an accurate representation of the resource's capabilities given the confines of the PJM software.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from ~~non-emergency~~ generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ located within the metered boundaries of the PJM Region. A resource is not eligible to provide Synchronized Reserve if its entire output has been designated as emergency energy or if the resource is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. ~~All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Tariff, Attachment K Appendix, section 2.5(d) and the parallel provision of Operating Agreement, Schedule 1, section 2.5(d), all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves.~~ Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary Reserve Requirement and Synchronized Reserve Requirement objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit

the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

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

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Non-Synchronized Reserve if (i) its Resources, the entire output of which has been designated as emergency energy, (ii) it is not and resources that aren't available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection ~~are not eligible~~ to provide Non-Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve ~~objective~~

Requirement for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

~~(d) — The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability of a generation resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.~~

~~(e) — All Non-Synchronized Reserve offers shall be for \$0.00/MWh.~~

1.7.19A.02 Secondary Reserve.

(a) Secondary Reserve can be supplied from synchronized and non-synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region, as specified in the PJM Manuals. A resource is not eligible to provide Secondary Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Secondary Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers and Market Sellers offering Secondary Reserve shall comply with applicable standards and requirements for Secondary Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone, as applicable, an amount of Secondary Reserve such that the sum of the Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve meets the respective 30-minute Reserve Requirement for each such Reserve Zone and Reserve Sub-zone, as applicable, and as specified in the PJM Manuals. In accordance with the PJM Manuals, the Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the 30-minute Reserve Requirement in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Secondary Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 30-minute period, minus the increase in energy output or load reduction achievable within a continuous 10-minute period.

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

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

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

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

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

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

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

1.7.20 Communication and Operating Requirements.

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

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

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

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

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

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic

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

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.10 Scheduling.

1.10.1 General.

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

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

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

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

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection

determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of [Operating Agreement, Schedule 1, Ssection 1.13](#) ~~of this Schedule 1 of this Agreement~~. Scheduling shall be conducted as specified in [Ssection 1.10.1A](#) below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with [Operating Agreement, Schedule 1, Ssections 3.2.3 and Operating Agreement, Schedule 1, section 6.6](#) ~~hereof~~.

1.10.1A Day-ahead [and Real-time](#) Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed \$2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to \$2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to [Operating Agreement, Schedule 1, Section 1.12](#); and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and

sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to \$2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, -or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this ~~Section 1.10.1A(d)~~, ~~Section 1.10.9B below~~, Operating Agreement, ~~Schedule 2-of-the-Operating Agreement~~, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This

includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or [Economic Load Response Participant resource](#) ~~Demand Resource~~ and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; ~~and~~ (12) emergency maximum MW; [\(13\) Synchronized Reserve maximum MW; \(14\) Secondary Reserve maximum MW; and \(15\) condense to generation time constraints](#), and may specify offer parameters for [Economic Load Response Participant resources](#) ~~Demand Resources~~ for

each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour;
- ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour;
- x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

- a) a 30 minute lead time, pursuant to [Tariff, Attachment DD-1, Section A.2](#) ~~of Attachment DD-1 of the Tariff~~ and the parallel provision of [RAA, Schedule 6](#) ~~of the RAA~~, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;
- b) an approved 60 minute lead time, pursuant to [Tariff, Attachment DD-1, Section A.2](#) ~~of Attachment DD-1 of the Tariff~~ and the parallel provision of [RAA, Schedule 6](#) ~~of the RAA~~, \$1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and
- c) an approved 120 minute lead time, pursuant to [Tariff, Attachment DD-1, Section A.2](#) ~~of Attachment DD-1 of the Tariff~~ and the parallel provisions of [RAA, Schedule 6](#) ~~of the RAA~~, \$1,100/megawatt-hour; and

- xi) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

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

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with [Operating Agreement, Schedule 1, Sections 3.2.3 and Operating Agreement, Schedule 1, section 6.6 hereof](#).

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

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

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

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the

average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be \$0.02/MWh, and for the period from the second month after implementation through the second January 1 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the

resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring

Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers ~~A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to~~

~~provide Synchronized Reserve that~~ shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, ~~the price of the offer in dollars per megawatt hour,~~ and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer ~~and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs.~~ Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable. ~~The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.~~

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, ~~start-up~~shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource~~Demand Resource~~ that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Economic Load Response Participant resource~~Demand Resource~~. The submission of demand reduction bids for Economic Load Response Participant resource~~Demand Resource~~ increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource~~Demand Resource~~ that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or

Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources~~Demand Resources~~ to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of

the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and

wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for \$0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

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

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = -greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy

Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to ~~S~~sections 1.10.9 below or Operating Agreement, Schedule 1, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in sSection 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

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

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

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

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

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which ~~offer~~ must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an

incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

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

- (a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.
- (b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.
- (c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.
- (d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.
- (e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.
- (e) For energy, Hhydropower units, excluding pumped storage units, may only be self-scheduled.
- (f) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

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

Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

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

1.10.5 External Resources.

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

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

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

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load

within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

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

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

1.10.7 Bilateral Transactions.

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

1.10.8 Office of the Interconnection Responsibilities.

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

constraints on external coordinated flowgates to the extent provided by [Operating Agreement, Schedule 1](#), section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in [Section 1.10.8\(b\)](#), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to [Operating Agreement, Schedule 1, Section 3.3A](#) ~~of this Schedule~~. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will

be based on the real-time quantities and prices as determined pursuant to [Operating Agreement, Schedule 1, Sections 2.4 and Operating Agreement, Schedule 1, section 2.5](#) ~~hereof~~.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market [or Day-ahead Ancillary Services Markets, or the Real-time Energy Market, or Real-time Ancillary Services Markets](#) ~~or Day-Ahead Scheduling Reserve Market~~ after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the ~~Ancillary Services Markets and~~ Real-time Energy Market [and Real-time Ancillary Services Markets](#), and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the ~~Day-ahead Scheduling Reserve Market and~~ Day-ahead Energy Market [and Day-ahead Ancillary Services Markets](#). After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the ~~Ancillary Services Markets and~~ Real-time Energy Market [and Real-time Ancillary Services Markets](#), and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the ~~Day-ahead Scheduling Reserve Market and the~~ Day-ahead Energy Market [and Day-ahead Ancillary Services Markets](#). *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the ~~Ancillary Services Markets, Day-ahead Energy Market, and~~ Real-time Energy Market, [and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets](#) ~~and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market~~. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

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

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the

results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A ~~of this Schedule~~ [below](#):

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this ~~S~~[section](#) 1.10, the Office of the Interconnection shall provide

External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; ~~and~~ (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, [Secondary Reserve](#), [Synchronized Reserve](#), [Non-Synchronized Reserve](#), or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; [\(7\) Synchronized Reserve maximum MW](#); [\(8\) Secondary Reserve maximum MW](#); and ~~(69)~~ for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

(c) For [Economic Load Response Participant resource](#) ~~Demand Resource~~ offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11 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 [Economic Load Response Participant resources](#) ~~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 [Operating Agreement, Schedule 1, s](#)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 [Economic Load Response Participant resources](#) ~~Demand Resources~~ as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or [Economic Load Response Participant resources](#) ~~Demand Resources~~ offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and [Economic Load Response Participant resource](#) ~~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 Economic Load Response Participant resources ~~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 Economic Load Response Participant resources ~~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~~ energy 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 Economic Load Response Participant resources ~~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 Operating Agreement, Schedule 1, s ~~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 available either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ as needed to meet the Synchronized Reserve ~~R~~ requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market. Resources ~~offering to sell Synchronized Reserve~~ shall be ~~selected~~ cleared to provide Synchronized Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource ~~Demand Resource~~'s Synchronized Reserve offer and the ~~estimated unit specific opportunity cost of the resource~~ product substitution cost of providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, ~~Operating Reserves,~~ and of meeting the

Synchronized Reserve [Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement.](#) However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product, ~~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) The Office of the Interconnection shall dispatch generation resources and/or [Economic Load Response Participant resources](#) ~~Demand Resources~~ for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or [Economic Load Response Participant resources](#) ~~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~~ [energy](#) in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources 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 [Operating Agreement, Schedule 1, s](#) ~~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 ~~R~~requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Resources providing Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Non-Synchronized Reserve Market and the Real-time Non-Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Non-Synchronized Reserve Market. ~~Market Buyers.~~ Resources eligible to sell Non-Synchronized Reserve shall be ~~selected~~ cleared to provide Non-Synchronized Reserve on the basis of each ~~generation~~ resource's product substitution cost between ~~estimated unit specific opportunity cost of the resource~~ providing Non-Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement, 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 energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJM Settlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJM Settlement shall not be a contracting party to bilateral transactions between Market Participants.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each

Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

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

2.5 Calculation of Real-time Prices.

- (a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Operating Agreement, Schedule 1, section 2.4. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the applicable reserve requirements. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any monitored transmission constraints that may exist.
- (b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Operating Agreement, Schedule 1, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.
- (c) In performing the Real-time Price calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as described in Operating Agreement, Schedule 1, section 2.4 as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative), including Transmission Constraint Penalty Factors, associated with increasing the output of a generation resource or decreasing the consumption by a Demand

Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(d) During the Operating Day, the calculation set forth in Operating Agreement, Schedule 1, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

2.5.1 Declaration of Shortage Pricing

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a [30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage](#) for the purposes of declaring shortage pricing as further described in the PJM Manuals. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, Real-time Prices shall be calculated as described in Operating Agreement, Schedule 1, section 2.5 and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When the Real-time Price software determines that a [30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage](#) exists, whereby the reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the Office of Interconnection shall implement shortage pricing. During shortage pricing, the Real-time Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement [consistent with the determination of the clearing price for each reserve product](#), and the components of Locational Marginal Prices referenced in Operating Agreement, Schedule 1, section 2.5 above shall be calculated as described below. Shortage pricing shall exist until the Real-time Price software program is able to meet the specified reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect.

(b) If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including

but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the [30-minute Reserve Requirement](#), the [Primary Reserve Requirement](#), and ~~the Reserve Penalty Factor for the Synchronized Reserve Requirement~~ are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, the [Secondary Reserve Market Clearing Price](#), and Locational Marginal Price, as applicable [and consistent with the provisions for determining those prices](#). The Reserve Penalty Factors [for the 30-minute Reserve Requirement](#), ~~for the Primary Reserve Requirement~~, and ~~the Reserve Penalty Factor for the Synchronized Reserve Requirement~~ will continue to be used in the

Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, [Secondary Reserve Market Clearing Price](#), and Locational Marginal Price calculation, as applicable [and consistent with the provisions for determining those prices](#), until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the [30-minute Reserve Requirement](#), the Primary Reserve Requirement, and ~~the Reserve Penalty Factor for the~~ Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, [Secondary Reserve Market Clearing Price](#), and Locational Marginal Price, as applicable [and consistent with the provisions for determining those prices](#). The Reserve Penalty Factors for the [30-minute Reserve Requirement](#), the Primary Reserve Requirement, and the ~~Reserve Penalty Factor for the~~ Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable [and consistent with the provisions for determining those prices](#), until the Manual Load Dump Action has been terminated.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Operating Agreement, Schedule 1, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, ~~Day-ahead Scheduling Reserve~~ offers for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. ~~The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Day-ahead Price at that bus.~~ The day-ahead Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource

constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

(b) The Office of the Interconnection shall use its day-ahead market clearing software to forecast if the Office of the Interconnection will experience a shortage of the 30-minute Reserve Requirement, Extended 30-minute Reserve Requirement, the Primary Reserve Requirement, Extended Primary Reserve Requirement, the Synchronized Reserve Requirement, and/or the Extended Synchronized Reserve Requirement, as further described in the PJM Manuals. If the day-ahead market clearing software forecasts that a shortage of any of the reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Day-ahead Locational Marginal Prices consistent with the determination of the clearing price for each reserve product. Shortage pricing shall exist until the day-ahead market clearing software is able to meet the specified reserve requirements.

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with [Operating Agreement, Schedule 1, Section 2](#) ~~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 [Operating Agreement, Schedule 1](#), 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 below](#), 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 below~~ shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in [Operating Agreement, Schedule 1](#), 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 [Economic Load Response Participant resources](#) ~~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 [Economic Load Response Participant resources](#) ~~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:

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

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 [Operating Agreement, Schedule 1](#), 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 ~~sSections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 of Schedule 1 of this Agreement~~ below does not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Day-ahead Scheduling Reserves Requirements, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market ~~Day-ahead Scheduling Reserves Requirement~~. PJM Settlement 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 ~~sSection 3.2.3(n)~~ below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources ~~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 [sSection 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 [sSection 3.2.3\(b\)](#) plus any unallocated charges from [sSection 3.2.3\(h\)](#) and [Operating Agreement, Schedule 1, section 5.1.7](#), and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves 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 [Operating Agreement, Schedule 1, sSection 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 [Tariff, 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 Economic Load Response Participant resources~~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 Economic Load Response Participant resources~~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 Economic Load Response Participant resources~~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 the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, ~~any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost~~, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below ~~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 the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve ~~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~~Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and ~~Day-ahead Scheduling~~Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, Section 1.10.3(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC D 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 [Operating Agreement, Schedule 1, s](#)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 ~~LOC D~~ 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 [Operating Agreement, Schedule 1, s](#)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 [Tariff, 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-~~t~~Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to [Operating Agreement, Schedule 1](#), section 1.12 ~~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-~~t~~Time Settlement Intervals for that hour;

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

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with [Operating Agreement, Schedule 1](#), section 3.1A ~~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 [Tariff, 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~~ [below](#), 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, [Secondary Reserve](#), or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, [Secondary Reserve](#), or Reactive Services, at the request of the Office of the Interconnection.

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

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, [Secondary Reserve](#), or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (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 [Operating Agreement, Schedule 1, Section 1.12](#), as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared (“Maximum Generation Emergency Alert”); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by [Section 3.2.3\(b\)](#) or [Section 3.2.3\(e\)](#) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide

timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as “MaxGen Conditions”). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with [Operating Agreement, Schedule 2](#) ~~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 [Operating Agreement, Schedule 1, s](#)Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by [Operating Agreement, Schedule 1, s](#)Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with [Operating Agreement, Schedule 1, s](#)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 [s](#)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 [s](#)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 [s](#)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. $LAtime = \text{Dispatch look ahead time}$
4. $Case_Eff_time = \text{Time between signal changes}$
5. $RL_Desired = \text{Ramp-limited desired MW}$

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: $\text{Real-time Settlement Interval MWh} - \text{dispatch LMP Desired MWh}$.
- 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: $\text{Real-time Settlement Interval MWh} - \text{Day-Ahead MWh}$.
- 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: $\text{Real-time Settlement Interval MWh} - \text{Day-Ahead MWh}$.

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 Response Participant ~~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 Operating Agreement, Schedule 1, 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 Operating Agreement, Schedule 1, sSection 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 [Tariff](#), 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 exceeds the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges 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 Operating Agreement, Schedule 1, sSection 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 sSection 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 Tariff, Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, sSection 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 sSection 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, Operating Agreement, 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, Operating Agreement, 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 Operating Agreement, Schedule 1, 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's ~~with an~~ hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below ~~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 and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market~~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 equal to the product of the higher of (i) the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide, 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.

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.~~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) [Reserved for future use]~~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) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

(dii) For the Real-time Synchronized Reserve Market, ~~The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. 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~~price of serving the next increment of demand for Synchronized Reserve in ~~each~~a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using ~~inclusive of~~ Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute. ~~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 Real-time Synchronized Reserve Market 5-minute c~~l~~e~~a~~r~~i~~n~~g~~ ~~p~~p~~r~~i~~c~~e shall be the sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement for ~~that each~~ Reserve Zone or Reserve Sub-zone to which it can contribute.

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

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

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the

Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) (i) ~~For each Real-time Settlement Interval and for~~ determining the ~~5-minute~~ Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated ~~unit~~resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall ~~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 = T~~he difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus ~~for the generation resource~~ and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch Synchronized Reserve set-point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, t~~The opportunity costs for a Demand Resource~~shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide ~~Tier-2~~ Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the ~~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 operating hour ~~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:

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

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~~ A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

~~C~~ B = The deviation of the ~~generation~~ resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment ~~follow the Office of the Interconnection's signals and instructions~~ from the ~~generation~~ resource's energy expected output or load reduction level if it had been ~~dispatched~~ assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

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

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, capped at the amount of Synchronized Reserve the resource responded during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A]

plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B + C + D) - (E + F + G + H)$$

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

~~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) ~~[Reserved for future use] 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) ~~For each operating hour, the sum of the Any amounts credited for Tier 2 Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above 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 real-time purchases of Synchronized Reserve in megawatt-hours during that hour.~~

(i) ~~[Reserved for future use] 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) In the event a generation resource or Economic Load Response Participant Resource ~~Demand Resource~~ that either has been assigned by the Office of the Interconnection or self-scheduled to provide ~~Tier 2~~ Synchronized Reserve in real-time fails to provide the assigned or self-scheduled amount of ~~Tier 2~~ Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be charged at the Real-time ~~credited for Tier 2~~ Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource, capacity ~~in the excess of~~ amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled ~~Tier 2~~ Synchronized Reserve real-time on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for ~~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 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 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 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 resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time 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 retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts ~~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 an Economic Load Response Participant resource ~~Demand Resource~~, except for Batch Load Economic Load Response Participant resource ~~Demand Resources~~ covered by section 3.2.3A(1), is the difference between the generation resource's output or the Economic Load Response Participant resource ~~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 [Economic Load Response Participant resource](#) ~~Demand Resource~~ consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest [Economic Load Response Participant resource](#) ~~Demand Resource~~ consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an [Economic Load Response Participant resource](#) ~~Demand Resource~~'s consumption 10 minutes after the event is defined as the greatest generator resource output or lowest [Economic Load Response Participant resource](#) ~~Demand Resource~~ consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an [Economic Load Response Participant resource](#) ~~Demand Resource~~ will be reduced by the amount the megawatt consumption of the [Economic Load Response Participant resource](#) ~~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 [Economic Load Response Participant resource](#) ~~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 [Economic Load Response Participant resource](#) ~~Demand Resource~~'s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load [Economic Load Response Participant resource](#) ~~Demand Resource~~'s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load [Economic Load Response Participant resource](#) ~~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's ~~with an~~ hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below ~~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) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:~~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.~~

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

(e)ii) For the Real-time Non-Synchronized Reserve Market, t~~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~~ price of serving the next increment of demand for Primary Reserve ~~procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each a~~ Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.~~ ~~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 Real-time Non-Synchronized Reserve Market 5-minute Clearing Price shall be sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement and the Reserve Penalty Factor for the Primary Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute~~that Reserve Zone or Reserve Sub-zone.~~

(iii) The Reserve Penalty Factor for the ~~Synchronized~~ Primary Reserve Requirement shall be \$850/MWh.

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

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

(d) (i) For ~~each Real-time Settlement Interval and for~~ determining the ~~5-minute~~ Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, 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:~~ zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

~~(A x 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) [Reserved for future use] ~~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) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above ~~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 real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.~~

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

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of

Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 ~~Day-ahead Scheduling~~ Secondary Reserves.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.~~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) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below. ~~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 (e) of this section.~~

~~(c) [Reserved for future use] 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) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone

by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirements for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be \$300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor for 30-minute Reserve are warranted for subsequent Delivery Year(s).
~~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 (e) 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.(i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load

Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

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

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

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

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero,

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B) - (C + D + E + F)$$

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in

the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing Secondary Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves

shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

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

(b) At the end of each Operating Day, where the active energy output 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 sSections 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 Operating Agreement, Schedule 1, sSection 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 Operating Agreement, Schedule 1, ssection 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 ssection 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 [Operating Agreement, Schedule 1, 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 $\{(AG - LMP_{DMW}) \times (UB - URTLMP)\}$ where:

AG equals the actual output of the unit;

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the 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 [Operating Agreement, Schedule 1, Section 1.10.3 \(c\)](#) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, 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-applicable~~ Synchronized Reserve ~~R~~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 ~~s~~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 Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource

provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the 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 [Operating Agreement, Schedule 1, s](#)~~Section 5-of this Schedule.~~

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in [Operating Agreement, Schedule 1, s](#)~~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 [\\$850/MWh](#)~~the energy offer cap plus the sum of the applicable Reserve Penalty Factors~~

~~for the Synchronized Reserve Requirement and Primary Reserve Requirement~~, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

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

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in [Operating Agreement, Schedule 1, s](#)~~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 [Operating Agreement, s](#)~~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 C

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

Effective December 31, 9998

(Identified by Additional Cover Pages)

(Clean Format)

Sections of the
PJM Open Access Transmission Tariff

Effective December 31, 9998

(Clean Format)

Definitions – A - B

30-minute Reserve:

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Affected System:

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider’s Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

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

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

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

Annual Resource Price Adder:

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

Annual Revenue Rate:

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection

Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Demand Resource Constraint:

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery

Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Resource:

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity

Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

Base Load Generation Resource

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Economic Load Response Participant Resource:

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

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

“Black Start Service” shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

“Border Yearly Charge” shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

“Breach” shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

“Breaching Party” shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

“Business Day” shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

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

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – C-D

Canadian Guaranty:

“Canadian Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

“Cancellation Costs” shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

“Capacity” shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

“Capacity Export Transmission Customer” shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

“Capacity Import Limit” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

“Capacity Interconnection Rights” shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

“Capacity Performance Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

“Capacity Resource with State Subsidy” shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

Capacity Resource Clearing Price:

“Capacity Resource Clearing Price” shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

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

Capacity Transmission Injection Rights:

“Capacity Transmission Injection Rights” shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

“Charge Economic Maximum Megawatts” shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

“Charge Economic Minimum Megawatts” shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

“Charge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

“Charge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cleared Capacity Resource with State Subsidy:

“Cleared Capacity Resource with State Subsidy” shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting

engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

“Collateral” shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. “Collateral” shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

“Collateral Call” shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Commencement Date:

“Commencement Date” shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The “Committed Offer” shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

“Completed Application” shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Composite Energy Offer:

“Composite Energy Offer” for generation resources shall mean the sum (in \$/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in \$/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

Conditional Incremental Auction:

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

Conditioned State Support:

“Conditioned State Support” shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where “conditioned on clearing in any RPM Auction” refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

“CONE Area” shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

“Confidential Information” shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through

inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

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

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

“Contingent Facilities” shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request’s costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

“Controllable A.C. Merchant Transmission Facilities” shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

Cost of New Entry:

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

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not

be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

Credit Affiliate:

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

"Credit Available for Export Transactions" shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable

Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailement:

"Curtailement" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailement Service Provider:

“Curtailment Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

“Customer Interconnection Facilities” shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer’s side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

“Daily Deficiency Rate” shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

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

Deactivation:

“Deactivation” shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

“Deactivation Avoidable Cost Credit” shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, Part V, section 115 .

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the

applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

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

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or (“DR Factor”) shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

“Designated Agent” shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

“Designated Entity” shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

“Direct Assignment Facilities” shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

“Discharge Economic Maximum Megawatts” shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

“Discharge Economic Minimum Megawatts” shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

“Discharge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate:

“Discharge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

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

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

“Dynamic Transfer” shall have the same meaning provided in the Operating Agreement.

Definitions – E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:

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

Electrical Distance:

“Electrical Distance” shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

“Eligible Customer” shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency Action:

“Emergency Action” shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

Emergency Condition:

“Emergency Condition” shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

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

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

“Energy Resource” shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

“Energy Settlement Area” shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

“Energy Transmission Injection Rights” shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

“Entity Providing Supply Services to Default Retail Service Provider” shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

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

Event of Default:

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Exercise of Buyer-Side Market Power:

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

“Export Nodal Reference Price” at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

“Export Transaction” shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

“Export Transaction Price Factor” for a prospective time interval shall be the greater of (i) PJM’s forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction’s dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

“Export Transaction Screening” shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Summer Demand Resource:

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

Extended Summer Resource Price Adder:

“Extended Summer Resource Price Adder” shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

“Extended 30-minute Reserve Requirement” shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

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

External Resource:

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

Facilities Study:

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

“Financial Close” shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized

certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

“Financial Default” shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall mean Transmission Service under the Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

“Firm Transmission Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

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

Foreign Guaranty:

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

“Forward Hourly LMPs” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, “FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum

net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

“FTR Participant” shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM’s FTR market.

FTR Portfolio Auction Value:

“FTR Portfolio Auction Value” shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offers for a generation resource.

Full Notice to Proceed:

“Full Notice to Proceed” shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – L – M – N

Legacy Policy:

“Legacy Policy” shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will

not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner’s system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

“Load Interest” shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

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

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

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

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

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

Locational Deliverability Area Reliability Requirement:

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

Locational Price Adder:

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

Locational Reliability Charge:

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

Locational UCAP:

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

Locational UCAP Seller:

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

Long-lead Project:

“Long-lead Project” shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

“Marginal Value” shall mean the incremental change in system dispatch costs, measured as a \$/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

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

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

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

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

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

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

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

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any

Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment

T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

“Minimum Extended Summer Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

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

Minimum Participation Requirements:

“Minimum Participation Requirements” shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

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

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be

formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria

and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

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

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Services Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

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

Nominated Energy Efficiency Value:

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

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

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

Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

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

Normal Minimum Generation:

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

Definitions – O – P - Q

Obligation:

“Obligation” shall mean all amounts owed to PJM Settlement for purchases from the PJM Markets, Transmission Service, (under both Tariff, Part II and Tariff, Part III), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJM Settlement in the future for capacity purchases within the PJM capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Offer Data:

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

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

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

On-Site Generators:

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

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

“Open Access Same-Time Information System,” “PJM Open Access Same-Time Information System” or “OASIS” shall mean the electronic communication and information system and

standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve Demand Curve:

"Operating Reserve Demand Curve" shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement.

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy from the external Generation Capacity Resource to loads in the PJM Region in a manner

comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

“Opportunity Cost” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

OPSI Advisory Committee:

“OPSI Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

“Option to Build” shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

“Optional Interconnection Study” shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

“Optional Interconnection Study Agreement” shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

“Part I” shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

“Part II” shall mean Tariff, Part II, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

“Part III” shall mean Tariff, Part III, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

“Part IV” shall mean Tariff, Part IV, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

“Part V” shall mean Tariff, Part V, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

“Part VI” shall mean Tariff, Part VI, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

“Participant” shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer.

Parties:

“Parties” shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

“Peak-Hour Dispatch” shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle), plus 10% of such costs *only for the 2022/2023 Delivery Year*, for at

least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate, plus 10% of such costs *only for the 2022/2023 Delivery Year*, under the same conditions as described above for the Day-ahead Energy Market.

Peak Market Activity:

“Peak Market Activity” shall mean a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of Tariff, Attachment Q, section VII.A. Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

Peak Season:

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

Percentage Internal Resources Required:

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

Performance Assessment Interval:

“Performance Assessment Interval” shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September.

Permissible Technological Advancement:

“Permissible Technological Advancement” shall mean a proposed technological change such as an advancement to turbines, inverters, plant supervisory controls or other similar advancements to the technology proposed in the Interconnection Request that is submitted to the Transmission Provider no later than the return of an executed Facilities Study Agreement (or, if a Facilities Study is not required, prior to the return of an executed Interconnection Service Agreement). Provided such change may not: (i) increase the capability of the Generating Facility as specified in the original Interconnection Request; (ii) represent a different fuel type from the original Interconnection Request; or (iii) cause any material adverse impact(s) on the Transmission System with regard to short circuit capability limits, steady-state thermal and voltage limits, or

dynamic system stability and response. If the proposed technological advancement is a Permissible Technological Advancement, no additional study will be necessary and the proposed technological advancement will not be considered a Material Modification.

PJM:

“PJM” shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

“PJM Administrative Service” shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

“PJM Entities” shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM’s officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

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

PJM Interchange Energy Market:

“PJM Interchange Energy Market” shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

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

PJM Interchange Import:

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

PJM Liaison:

“PJM Liaison” shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

“PJM Management” shall mean the officers, executives, supervisors and employee managers of PJM.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Markets:

“PJM Markets” shall mean the PJM Interchange Energy Market, capacity markets, including the RPM auctions, and any other market operated by PJM, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions, Financial Transmission Rights

transactions, or transactions in any other market operated under the Agreements within the PJM Region, wherein Market Participants may incur Obligations to PJM and/or PJMSettlement.

PJM Market Rules:

“PJM Market Rules” shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

“PJM Net Assets” shall mean the total assets per PJM’s consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

“PJM Region” shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:

“PJM Regional Practices Document” shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to RAA, Schedule 4.1, as approved by the PJM Board.

PJM Region Peak Load Forecast:

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

PJM Region Reliability Requirement:

“PJM Region Reliability Requirement” shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast,

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

PJMSettlement:

“PJM Settlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” “OATT,” or “PJM Open Access Transmission Tariff” shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

“Plan” shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

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

Planned External Financed Generation Capacity Resource:

“Planned External Financed Generation Capacity Resource” shall mean a Planned External Generation Capacity Resource that, prior to August 7, 2015, has an effective agreement that is the equivalent of an Interconnection Service Agreement, has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close, and has secured at least 50 percent of the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Planned External Generation Capacity Resource:

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

Planned Financed Generation Capacity Resource:

“Planned Financed Generation Capacity Resource” shall mean a Planned Generation Capacity Resource that, prior to August 7, 2015, has an effective Interconnection Service Agreement and has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close.

Planned Generation Capacity Resource:

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

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Planning Period Balance:

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

Planning Period Quarter:

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

Point(s) of Delivery:

“Point(s) of Delivery” shall mean the point(s) on the Transmission Provider’s Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

“Point of Interconnection” shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

“Point(s) of Receipt” shall mean point(s) of interconnection on the Transmission Provider’s Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

“Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

“Power Purchaser” shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

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

PRD Provider:

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

PRD Reservation Price:

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

PRD Substation:

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

Pre-Confirmed Application:

“Pre-Confirmed Application” shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

“Pre-Emergency Load Response Program” shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Pre-Expansion PJM Zones:

“Pre-Expansion PJM Zones” shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC (“MAIT”) (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

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

Primary Reserve:

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

Primary Reserve Alert

“Primary Reserve Alert” shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Principal:

“Principal” shall mean (i) the chief executive officer or senior manager that controls or directs strategy for the Participant, (ii) the chief legal officer or general counsel, (iii) the chief financial officer or senior manager that controls or directs the financial affairs and investments of the Participant, (iv) the chief risk officer or senior manager responsible for managing commodity and derivatives market risks, and (v) the officer or senior manager responsible for or to be responsible for transactions in the applicable PJM Markets. If, due to the Participant’s business enterprise, structure or otherwise, the functions attributed to any of such Principals are performed by an individual or entity separate from the Participant (such as a risk management department in an affiliate, or a director or manager at an entity that controls or invests in the Participant), then for that Participant the term Principal shall mean that individual, or the senior officer or manager of that entity, that performs such function.

Prior CIL Exception External Resource:

“Prior CIL Exception External Resource” shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan

under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

“Project Financing” shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer’s obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

“Project Finance Entity” shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer’s obligations under the corresponding power purchase agreement.

Projected EAS Dispatch:

“Projected EAS Dispatch” shall mean, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource’s offer and operating parameters. For combustion turbine units only, the cost-based energy offer will include a 10 percent adder *only for the 2022/2023 Delivery Year*.

Projected PJM Market Revenues:

“Projected PJM Market Revenues” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Provisional Interconnection Service:

“Provisional Interconnection Service” shall mean interconnection service provided by Transmission Provider associated with interconnecting the Interconnection Customer’s Generating Facility to Transmission Provider’s Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interconnection Service Agreement and, if applicable, the Tariff.

Pseudo-Tie:

“Pseudo-Tie” shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

“Public Policy Objectives” shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

“Public Policy Requirements” shall have the same meaning provided in the Operating Agreement.

Qualifying Transmission Upgrade:

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

Queue Position:

“Queue Position” shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

Definitions – R - S

Ramping Capability:

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

Real-time Congestion Price:

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

Real-time Loss Price:

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

Real-time Energy Market:

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

Real-time Offer:

“Real-time Offer” shall mean a new offer or an update to a Market Seller’s existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

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

Real-time Settlement Interval:

“Real-time Settlement Interval” shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

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

Reasonable Efforts:

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

Receiving Party:

“Receiving Party” shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

“Referral” shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

“Reference Resource” shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh.

Regional Entity:

“Regional Entity” shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

“Regional Transmission Expansion Plan” shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

“Regional Transmission Group” or “RTG” shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and

decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

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

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

“Reliability Assurance Agreement” or “PJM Reliability Assurance Agreement” shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

“Reliability Pricing Model Auction” or “RPM Auction” shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

“Regional Transmission Enhancements” shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B (“Appendix B Agreement”) designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

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

Reserve Penalty Factor:

“Reserve Penalty Factor” shall mean the cost, in \$/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

“Reserve Sub-zone” shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

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

Residual Auction Revenue Rights:

“Residual Auction Revenue Rights” shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

“Residual Metered Load” shall mean all load remaining in an electric distribution company’s fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource Substitution Charge:

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

Revenue Data for Settlements:

“Revenue Data for Settlements” shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

“RPM Seller Credit” shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

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

Schedule of Work:

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

Scope of Work:

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

Seasonal Capacity Performance Resource:

“Seasonal Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Reserve:

“Secondary Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand

can be reduced within 30 minutes (less the capability of such resources to provide Primary Reserve), from the request of the Office of the Interconnection, regardless of whether the equipment providing the reserve is electrically synchronized to the Transmission System or not.

Secondary Systems:

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

Second Incremental Auction:

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

Security:

“Security” shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer’s responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

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

Self-Supply Entity:

“Self-Supply Entity” shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where “vertically integrated utility” means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts;

“single customer entity” means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and “public power entity” means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

“Self-Supply Seller” shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where “vertically integrated utility” means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and “public power entity” means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

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

Service Agreement:

“Service Agreement” shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

“Service Commencement Date” shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

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

“Short-Term Firm Point-To-Point Transmission Service” shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

“Short-term Project” shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

“Short-Term Resource Procurement Target” shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:

“Short-Term Resource Procurement Target Applicable Share” shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

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

Small Commercial Customer:

“Small Commercial Customer,” as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a “small commercial customer” under the terms of the applicable RERRA’s program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

“Small Generation Resource” shall mean an Interconnection Customer’s device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer’s Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

“Small Inverter Facility” shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

“Small Inverter ISA” shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

“Special Member” shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

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

Spot Market Energy:

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

“Start Additional Labor Costs” shall mean additional labor costs for startup required above normal station manning levels.

Start-Up Costs:

“Start-Up Costs” shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

“State” shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

“State Commission” shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

“State Subsidy” shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

- (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or
- (2) will support the construction, development, or operation of a new or existing Capacity Resource; or
- (3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity’s obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing

herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

- (i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);
- (ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and
- (iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State of Charge:

“State of Charge” shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using minimum and maximum charge and discharge limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant's obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

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

Sub-Annual Resource Constraint:

“Sub-Annual Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

“Sub-Annual Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

“Sub-Annual Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery

Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

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

Sub-meter:

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

“Summer-Period Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

“Surplus Interconnection Customer” shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

“Surplus Interconnection Request” shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

“Surplus Interconnection Service” shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service

is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

“Switching and Tagging Rules” shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

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

Synchronized Reserve Event:

“Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System Condition:

“System Condition” shall mean a specified condition on the Transmission Provider’s system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer’s Service Agreement.

System Energy Price:

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of

energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

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

System Protection Facilities:

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

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the

relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric

distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated

hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
- b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
- c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
- d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the

matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

- b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

("Pilot Period"). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Economic Load Response Participant Resource Provision of Synchronized Reserve or Secondary Reserve.

(a) A Batch Load Economic Load Response Participant resource may provide Synchronized Reserve or Secondary Reserve in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Economic Load Response Participant resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Economic Load Response Participant resource" pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Economic Load Response Participant resource.

(b) A Batch Load Economic Load Response Participant resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Secondary Reserve, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Secondary Reserve, until a dispatch instruction that load reductions are no longer required. A Batch Load Economic Load Response Participant resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Secondary Reserve, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Secondary Reserve, until a dispatch instruction that load reductions are no longer required).

Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Secondary Reserve to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the Secondary Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;
- v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then

only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each End-Use Customer site must meet the requirements for market participation by an Economic Load Response Participant resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by an Economic Load Response Participant resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

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

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

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

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Economic Load Response Participant resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be

separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Operating Agreement, section 14, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

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

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Economic Load Response Participant resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Economic Load Response Participant resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Economic Load Response Participant resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the applicable interval Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in the applicable interval, shall

be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues from there shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Operating Agreement, Schedule 1, section 3. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

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

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

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

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

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

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

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not Dynamic Transfers pursuant to Operating Agreement, Schedule 1, section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such

resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

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

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), “net output” of a generation facility during any month means the facility’s gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility’s or a Market Seller’s monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as “remote self-supply of Station Power”), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility’s negative net output from Market Seller’s generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A; Tariff, Schedule 2; Tariff, Schedule 3; Tariff Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station

Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

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

(iv) The Office of the Interconnection is not responsible for determining Relevant Electric Retail Regulatory Authority-jurisdictional retail rates, and the monthly netting provision in section 1.7.10(d)(i) above does not determine whether a retail sale of station power has occurred in a month. Furthermore, notwithstanding any provision of subsection (d)(i) or (d)(ii) to the contrary, any net output determined for a Market Seller for Station Power purposes shall, as more fully set forth in the PJM manuals, take account of MWh values submitted to the Office of the Interconnection via its metering reporting systems by the Market Seller or the applicable Electric Distribution Company designated to make such submission, that reflect the Market Seller's purchase of energy at retail to meet its Station Power needs.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after

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

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

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

1.7.14 PJM Manuals.

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

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 [Reserved.]

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Economic Load Response Participant resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

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

(c) The Regulation range of a generation unit or Economic Load Response Participant resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

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

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator. Market Sellers must specify a ramping rate in the Offer Data that is an accurate representation of the resource's capabilities given the confines of the PJM software.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Synchronized Reserve if its entire output has been designated as emergency energy or if the resource is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow

dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary Reserve Requirement and Synchronized Reserve Requirement objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Non-Synchronized Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Non-Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal

supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve Requirement for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

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

1.7.19A.02 Secondary Reserve.

(a) Secondary Reserve can be supplied from synchronized and non-synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region, as specified in the PJM Manuals. A resource is not eligible to provide Secondary Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Secondary Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied,

the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers and Market Sellers offering Secondary Reserve shall comply with applicable standards and requirements for Secondary Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone, as applicable, an amount of Secondary Reserve such that the sum of the Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve meets the respective 30-minute Reserve Requirement for each such Reserve Zone and Reserve Sub-zone, as applicable, and as specified in the PJM Manuals. In accordance with the PJM Manuals, the Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the 30-minute Reserve Requirement in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Secondary Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 30-minute period, minus the increase in energy output or load reduction achievable within a continuous 10-minute period.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve.

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

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

Reserve, or Secondary Reserve, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

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

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

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

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

1.7.20 Communication and Operating Requirements.

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

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

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

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

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

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the

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

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.10 Scheduling.

1.10.1 General.

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

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

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

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

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of

conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Tariff, Attachment K-Appendix, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Tariff, Attachment K-Appendix, section 3.2.3 and Tariff, Attachment K-Appendix, section 6.6.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed \$2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to \$2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Tariff, Attachment K-Appendix, section 1.12; and

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

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum

difference between the source and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to \$2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

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

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

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

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

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

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

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

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

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

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour;

ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,000/megawatt hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, \$1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

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

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

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

thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Tariff, Attachment K-Appendix, section 3.2.3 and Tariff, Attachment K-Appendix, section 6.6.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

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

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

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity

Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be \$0.02/MWh, and for the period from the second month after implementation through the second January 1 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the

implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum;

and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such

hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The

offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response Participant resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve

maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify

the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for \$0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead

Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and

supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

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

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

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Tariff, Attachment K-Appendix, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

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

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

1.10.3 Self-scheduled Resources.

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

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

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

(g) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

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

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

1.10.5 External Resources.

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

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

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

1.10.6 External Market Buyers.

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

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

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

1.10.7 Bilateral Transactions.

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

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves

properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Tariff, Attachment K-Appendix, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Tariff, Attachment K-Appendix, section 3.3A. Notwithstanding the foregoing, if the

Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.5.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

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

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right

of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

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

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

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

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

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines

specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (9) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11 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 Economic Load Response Participant 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 Operating Agreement, Schedule 1, 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 Economic Load Response Participant resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant 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 Economic Load Response Participant 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 Economic Load Response Participant 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 energy 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 Economic Load Response Participant 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 Operating Agreement, Schedule 1, 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 available either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant 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. The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market. Resources shall be cleared to provide Synchronized Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Synchronized Reserve offer and the product substitution cost of providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a

minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Economic Load Response Participant 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 energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources 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 Operating Agreement, Schedule 1, 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 pool-scheduled generation resources, as needed to ensure the Primary Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Resources providing Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Non-Synchronized Reserve Market and the Real-time Non-Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Non-Synchronized Reserve Market. Resources eligible to sell Non-Synchronized Reserve shall be cleared to provide Non-Synchronized Reserve on the basis of each resource's product substitution cost between providing Non-Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement.

(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 energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve

instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

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

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Tariff, Attachment K-Appendix, section 2.4. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the applicable reserve requirements. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any monitored transmission constraints that may exist.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Tariff, Attachment K-Appendix, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.

(c) In performing the Real-time Price calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as described in Tariff, Attachment K-Appendix, section 2.4 as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative), including Transmission Constraint Penalty Factors, associated with increasing the output of a generation resource or decreasing the consumption by a Demand

Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(d) During the Operating Day, the calculation set forth in Tariff, Attachment K-Appendix, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

2.5.1 Declaration of Shortage Pricing

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a 30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage for the purposes of declaring shortage pricing as further described in the PJM Manuals. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, Real-time Prices shall be calculated as described in Tariff, Attachment K-Appendix, section 2.5 and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When the Real-time Price software determines that a 30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage exists, whereby the reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the Office of Interconnection shall implement shortage pricing. During shortage pricing, the Real-time Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement consistent with the determination of the clearing price for each reserve product, and the components of Locational Marginal Prices referenced in Tariff, Attachment K-Appendix, section 2.5 above shall be calculated as described below. Shortage pricing shall exist until the Real-time Price software program is able to meet the specified reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect.

(b) If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, the Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions

for determining those prices. The Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Manual Load Dump Action has been terminated.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Tariff, Attachment K-Appendix, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, offers for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. The day-ahead Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is

provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

(b) The Office of the Interconnection shall use its day-ahead market clearing software to forecast if the Office of the Interconnection will experience a shortage of the 30-minute Reserve Requirement, Extended 30-minute Reserve Requirement, the Primary Reserve Requirement, Extended Primary Reserve Requirement, the Synchronized Reserve Requirement, and/or the Extended Synchronized Reserve Requirement, as further described in the PJM Manuals. If the day-ahead market clearing software forecasts that a shortage of any of the reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Day-ahead Locational Marginal Prices consistent with the determination of the clearing price for each reserve product. Shortage pricing shall exist until the day-ahead market clearing software is able to meet the specified reserve requirements.

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Tariff, Attachment K-Appendix, section 2.

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

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region.

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation 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.

$$\text{Regulation Charge} = \text{Hourly Regulation Obligation Share} * (\text{sum of the Real-time Settlement Interval Regulation credits in an hour})$$

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 below, the 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 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Tariff, Attachment K-Appendix, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the 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 Economic Load Response Participant 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 Economic Load Response Participant 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:

$$\text{Accuracy Score} = \max ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

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 Tariff, Attachment K-Appendix, section 1.10.1A(e). 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 sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 below do not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Reserve Requirements, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

(b) 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) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve 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 Tariff, Attachment K-Appendix, section 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves 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 Tariff, Attachment K-Appendix, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of 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 Economic Load Response Participant resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

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 Economic Load Response Participant resources) costs for generation resources.

Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A * B) - C$.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a

Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3(f).
- (ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:
 - 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
 - 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output

due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind 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 LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(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 Tariff, Attachment K-Appendix, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid

pursuant to the Market Settlement provision of the real-time Economic Load Response Program, 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 Tariff, Schedule 6A, 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 Tariff, Attachment K-Appendix, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (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 Tariff, Schedule 6A.

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) below, 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, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (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 Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared (“Maximum Generation Emergency Alert”); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by section 3.2.3(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as “MaxGen Conditions”). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Tariff, Attachment K-Appendix, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Tariff, Attachment K-Appendix, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Tariff, Attachment K-Appendix, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. 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:

$$\text{Ramp_Request}_t = (\text{Dispatchtarget}_{t-1} - \text{AOutput}_{t-1}) / (\text{LTime}_{t-1})$$
$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + (\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1})$$

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. LTime = 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 Response Participant resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Tariff, Attachment K-Appendix, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, 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 exceeds the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges 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 Tariff, Attachment K-Appendix, section 3.2.3(h)(ii)(A) 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 Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Tariff, Attachment K-Appendix, 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, Operating Agreement, Schedule 2 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, Operating Agreement, Schedule 2, 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 Tariff, Attachment K-Appendix, section 6.4.3. 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's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide..

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using

Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be \$300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's energy expected output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, capped at the amount of Synchronized Reserve the resource responded during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-

time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A] plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B + C + D) - (E + F + G + H)$$

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource, in excess of amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less 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 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately

preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the

difference between (i) the Batch Load Economic Load Response Participant resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes. .

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the

price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement and the Primary Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Primary Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and

the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(\text{zero}) - (A + B + C + D)$$

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price

multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone,

plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Tariff, Attachment K-Appendix, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirements for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be \$300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from

the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource

shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero,

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time

reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

- (A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;
- (B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;
- (C) A resource's Final Offer is less than its Committed Offer;
- (D) A resource trips offline or otherwise becomes unavailable in real-time;
- (E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or
- (F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B) - (C + D + E + F)$$

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing Secondary Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output 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 Tariff, Attachment K-Appendix, section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's

bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output 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 Tariff, Attachment K-Appendix, 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 Tariff, Attachment K-Appendix, section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or

suspend a unit's output for the purpose of maintaining reactive reliability, 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 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 applicable Synchronized Reserve Requirements. Operators of these generation units shall be

notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the 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 Tariff, Attachment K-Appendix, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Tariff, Attachment K-Appendix, section 5.

3.2.6 Emergency Energy.

- (a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at \$850/MWh, 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 Tariff, Attachment K-Appendix, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.
- (b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered

Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

Sections of the
PJM Operating Agreement

Effective December 31, 9998

(Clean Format)

Definitions A - B

30-minute Reserve:

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

Act:

“Act” shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

“Active and Significant Business Interest” is a term that shall be used to assess the scope of a Member’s PJM membership and shall be based on a Member’s activity in the PJM RTO and/or Interchange Energy Markets. A Member’s Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member’s PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member’s public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member’s recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates’ interests within the PJM footprint.

Affected Member:

“Affected Member” shall mean a Member of PJM which as a result of its participation in PJM’s markets or its membership in PJM provided confidential information to PJM, which confidential

information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreement, Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Agreement,” “Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

Annual Meeting of the Members:

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Associate Member:

“Associate Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Commission:

“Authorized Commission” shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

“Authorized Person” shall have the meaning set forth in Operating Agreement, section 18.17.4.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Batch Load Economic Load Response Participant Resource:

“Batch Load Economic Load Response Participant Resource” shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

“Board Member” shall mean a member of the PJM Board.

Definitions C - D

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Catastrophic Force Majeure:

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

Charge Economic Maximum Megawatts:

“Charge Economic Maximum Megawatts” shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

“Charge Economic Minimum Megawatts” shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

“Charge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

“Charge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Committed Offer:

The “Committed Offer shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Compliance Monitoring and Enforcement Program:

“Compliance Monitoring and Enforcement Program” shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

Composite Energy Offer:

“Composite Energy Offer” for generation resources shall mean the sum (in \$/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in \$/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A and the PJM Manuals.

Congestion Price:

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or “Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other

transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the extent that energy serves that Member's own load.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45) Schedule A. The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C, Attachment 3, section 2.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment Service Provider:

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Day-ahead Congestion Price:

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

“Day-ahead System Energy Price” shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default Allocation Assessment:

“Default Allocation Assessment” shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

“Demand Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Designated Entity:

“Designated Entity” shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

Direct Charging Energy:

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

“Discharge Economic Maximum Megawatts” shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

“Discharge Economic Minimum Megawatts” shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

“Discharge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate:

“Discharge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

“Dispatch Rate” shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Dynamic Transfer:

“Dynamic Transfer” shall mean a Pseudo-Tie or Dynamic Schedule.

Definitions E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall mean an enhancement or expansion described in Operating Agreement, Schedule 6, section 1.5.7(b) (i) – (iii) that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

“Effective Date” shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EIDSN, Inc.:

“EIDSN, Inc.” shall mean the nonstock, nonprofit corporation, formerly known as Eastern Interconnection Data Sharing Network, Inc., or any successor thereto, that is operated primarily for the purpose of developing operating tools and the facilitation of the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among Reliability Coordinators and other relevant parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk electric system in the Eastern Interconnection.

Electric Distributor:

“Electric Distributor” shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency:

“Emergency” shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Member Committee classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Equivalent Load:

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

“Extended 30-minute Reserve Requirement” shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for an Operating Day.

Finance Committee:

“Finance Committee” shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offer(s) for a generation resource.

Definitions I - L

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall mean a reliability-based transmission enhancement or expansion that the Office of the Interconnection has identified to resolve a need that must be addressed within three years or less from the year the Office of the Interconnection identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3.

Inadvertent Interchange:

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean the cost in dollars per MWh of providing an additional MWh from a synchronized unit. It consists primarily of the cost of fuel, as determined by the unit’s incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances, tax credits, and energy market opportunity costs.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Information Request:

“Information Request” shall mean a written request, in accordance with the terms of the Operating Agreement for disclosure of confidential information pursuant to Operating Agreement, section 18.17.4.

Integer Relaxation:

“Integer Relaxation” shall mean the process by which the commitment status variable for an Eligible Fast-Start Resource is allowed to vary between zero and one, inclusive of zero and one, as further described in Operating Agreement, Schedule 1, section 2.2.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Internal Market Buyer:

“Internal Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

LLC:

“LLC” shall mean PJM Interconnection, L.L.C., a Delaware limited liability company.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Local Plan:

“Local Plan” shall include Supplemental Projects as identified by the Transmission Owners within their zone and Subregional RTEP projects developed to comply with all applicable reliability criteria, including Transmission Owners’ planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

Locational Marginal Price:

“Locational Marginal Price” or “LMP” shall mean the market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Long-lead Project:

“Long-lead Project” shall mean a transmission enhancement or expansion with an in-service date more than five years from the year in which, pursuant to Operating Agreement, Schedule 6,

section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Definitions M - N

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Market Buyer:

“Market Buyer” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and/or PJM Settlement in Tariff, Attachment Q, and that is otherwise able to make purchases in the PJM Interchange Energy Market.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” shall mean the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, and/or an Economic Load Response Participant, except when that term is used in or pertaining to Tariff, Attachment M, Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4. “Market Participant,” when such term is used in Tariff, Attachment M, shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but

does not purchase or sell energy at wholesale. “Market Participant,” when such term is used in or pertaining to Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4, shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, an FTR Participant, a Capacity Market Buyer, or a Capacity Market Seller.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller:

“Market Seller” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and/or PJMSettlement in Tariff, Attachment Q, and that is otherwise able to make sales in the PJM Interchange Energy Market.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Operating Agreement, Schedule 4.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

Minimum Generation Emergency:

“Minimum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM’s State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

“Multi-Driver Project” shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation, or any successor thereto.

NERC Functional Model:

“NERC Functional Model” shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

NERC Reliability Standards:

“NERC Reliability Standards” shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.

NERC Rules of Procedure: “NERC Rules of Procedure” shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Network Resource:

“Network Resource” shall have the meaning specified in the PJM Tariff.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Non-Disclosure Agreement:

“Non-Disclosure Agreement” shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Operating Agreement, section, the form of which is appended to this Agreement as Operating Agreement, Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Nonincumbent Developer:

“Nonincumbent Developer” shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, 1.5A.6.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions O - P

Offer Data:

“Offer Data” shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the Transmission System in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

“Office of the Interconnection Control Center” shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

On-Site Generators:

“On-Site Generators” shall mean generation facilities or portions of a generation facility (including Behind The Meter Generation) that (i) are not Generation Capacity Resources, (ii) are not injecting into the grid for the portion of a generation facility that participates as an Economic Load Response Participant or as a Demand Resource, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-time Information System:

“Open Access Same-Time Information System,” “PJM Open Access Same-time Information System” or “OASIS” shall mean the electronic communication system and information system and standards of conduct contained in Part 37 and Part 38 of the Commission’s regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Day:

“Operating Day” shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

Operating Margin:

“Operating Margin” shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

Operating Margin Customer:

“Operating Margin Customer” shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Operating Reserve Demand Curve:

“Operating Reserve Demand Curve” shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement.

Operator-initiated Commitment:

“Operator-initiated Commitment” shall mean a commitment after the Day-ahead Energy Market and Day-ahead Scheduling Reserves Market, whether manual or automated, for a reason other than minimizing the total production costs of serving load.

Original PJM Agreement:

“Original PJM Agreement” shall mean that certain agreement between certain of the Members, originally dated September 26, 1956, and as amended and supplemented up to and including December 31, 1996, relating to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and; (ii) does not qualify for the Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer sectors.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Dispute Resolution Procedures:

“PJM Dispute Resolution Procedures” shall mean the procedures for the resolution of disputes set forth in Operating Agreement, Schedule 5.

PJM Governing Agreements:

“PJM Governing Agreements” shall mean the PJM Open Access Transmission Tariff, the Operating Agreement, the Consolidated Transmission Owners Agreement, the Reliability Assurance Agreement, or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and any of its Members.

PJM Interchange:

“PJM Interchange” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds, or is exceeded by, the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller; or (e) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Interchange Energy Market:

“PJM Interchange Energy Market” shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix.

PJM Interchange Export:

“PJM Interchange Export” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load is exceeded by the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

“PJM Interchange Import” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Mid-Atlantic Region:

“PJM Mid-Atlantic Region” shall mean the aggregate of the Transmission Facilities of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

PJM Region:

“PJM Region” shall mean the aggregate of the Zones within PJM as set forth in Tariff, Attachment J.

PJMSettlement:

“PJMSettlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM South Region:

“PJM South Region” shall mean the Transmission Facilities of Virginia Electric and Power Company.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” or “PJM Open Access Transmission Tariff” shall mean that certain “PJM Open Access Transmission Tariff”, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

PJM West Region:

“PJM West Region” shall mean the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Affiliate Companies; The Dayton Power and Light Company; the Duquesne Light Company; American Transmission Systems, Incorporated; Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc. and East Kentucky Power Cooperative, Inc.

Planning Period:

“Planning Period” shall have the meaning specified in the Reliability Assurance Agreement.

Planning Period Balance:

“Planning Period Balance” shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

Planning Period Quarter:

“Planning Period Quarter” shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

Point-to-Point Transmission Service:

“Point-to-Point Transmission Service” shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Delivery under Tariff, Part II.

PRD Curve:

“PRD Curve” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Provider:

“PRD Provider” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Reservation Price:

“PRD Reservation Price” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Substation:

“PRD Substation” shall have the meaning provided in the Reliability Assurance Agreement.

Pre-Emergency Load Response Program:

“Pre-Emergency Load Response Program” shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-appendix, section 8.

President:

“President” shall have the meaning specified in Operating Agreement, section 9.2.

Price Responsive Demand:

“Price Responsive Demand” shall have the meaning provided in the Reliability Assurance Agreement.

Primary Reserve:

“Primary Reserve” shall mean the total reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Alert:

“Primary Reserve Alert” shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Prohibited Securities:

“Prohibited Securities” shall mean the Securities of a Member, Eligible Customer, or Nonincumbent Developer, or their Affiliates, if:

(1) the primary business purpose of the Member or Eligible Customer, or their Affiliates, is to buy, sell or schedule energy, power, capacity, ancillary services or transmission services as indicated by an industry code within the “Electric Power Generation, Transmission, and Distribution” industry group under the North American Industry Classification System (“NAICS”) or otherwise determined by the Office of the Interconnection;

(2) the Nonincumbent Developer has been pre-qualified as eligible to be a Designated Entity pursuant to Operating Agreement, Schedule 6;

(3) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during its most recently completed fiscal year is equal to or greater than 0.5% of its gross revenues for the same time period; or

(4) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during the prior calendar year is equal to or greater than 3% of the total transactions for which PJM Settlement is a Counterparty pursuant to Operating Agreement, section 3.3 for the same time period.

The Office of the Interconnection shall compile and maintain a list of the Prohibited Securities publicly traded and post this list for all employees and distribute the list to the Board Members.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Pseudo-Tie:

“Pseudo-Tie shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Public Policy Objectives:

“Public Policy Objectives” shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations.

Public Policy Requirements:

“Public Policy Requirements” shall refer to policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity.

Definitions S – T

Sector Votes:

“Sector Votes” shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

“Securities” shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

“Senior Standing Committees” shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

“SERC” or “Southeastern Electric Reliability Council” shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

“Short-term Project” shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

“Special Member” shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

“Spot Market Backup” shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Standing Committees:

“Standing Committees” shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start-Up Costs:

“Start-Up Costs” shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

“State” shall mean the District of Columbia and any State or Commonwealth of the United States.

State Certification:

“State Certification” shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State of Charge:

“State of Charge” shall mean the operating parameter that represents the quantity of physical energy stored (measured in units of megawatt-hours) in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using Charge and Discharge Economic Minimum and Maximum Megawatts limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant’s obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

“Station Power” shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-meter:

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Subregional RTEP Project:

“Subregional RTEP Project” shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

“Supplemental Project” shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

“Synchronized Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

“Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System:

“System” shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3 or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Party Request:

“Third Party Request” shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

“Tie Line” shall have the same meaning provided in the Open Access Transmission Tariff.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the

cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Customer:

“Transmission Customer” shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Operator:

“Transmission Operator” shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall mean an upgrade to a Transmission Owner’s own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages

specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the

relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric

distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated

hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
- b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
- c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
- d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the

matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

- b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

("Pilot Period"). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Economic Load Response Participant Resource Provision of Synchronized Reserve or Secondary Reserve.

(a) A Batch Load Economic Load Response Participant resource may provide Synchronized Reserve or Secondary Reserve in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Economic Load Response Participant resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Economic Load Response Participant resource" pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Economic Load Response Participant resource.

(b) A Batch Load Economic Load Response Participant resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Secondary Reserve, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Secondary Reserve, until a dispatch instruction that load reductions are no longer required. A Batch Load Economic Load Response Participant resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Secondary Reserve, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Secondary Reserve, until a dispatch instruction that load reductions are no longer required).

Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Secondary Reserve to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the Secondary Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;
- v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then

only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each End-Use Customer site must meet the requirements for market participation by an Economic Load Response Participant resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by an Economic Load Response Participant resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers and Energy Storage Resources shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Economic Load Response Participant resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with

Operating Agreement, section 14, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Tariff, section 36.1.1, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement, and as may be further described in the PJM Manuals, for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Economic Load Response Participant resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by

Market Sellers, continuing until sufficient generation resources and/or Economic Load Response Participant resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Economic Load Response Participant resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the applicable interval Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in the applicable interval, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues from there shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Operating Agreement, Schedule 1, section 3. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

- (i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its InSchedule and ExSchedule tools.
- (ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.
- (iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with

the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

- (iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.
- (v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.
- (vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not Dynamic Transfers pursuant to Operating Agreement, Schedule 1, section 1.12 and that

are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

- (i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.
- (ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of

energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A; Tariff, Schedule 2; Tariff, Schedule 3; Tariff, Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

- (iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.
- (iv) The Office of the Interconnection is not responsible for determining Relevant Electric Retail Regulatory Authority-jurisdictional retail rates, and the monthly netting provision in section 1.7.10(d)(i) above does not determine whether a retail sale of station power has occurred in a month. Furthermore, notwithstanding any provision of subsection (d)(i) or (d)(ii) to the contrary, any net output determined for a Market Seller for Station Power purposes shall, as more fully set forth in the PJM manuals, take account of MWh values submitted to the Office of the Interconnection via its metering reporting systems by the Market Seller or the applicable Electric Distribution Company designated to make such submission, that reflect the Market Seller's purchase of energy at retail to meet its Station Power needs.

1.7.11 Emergencies.

- (a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and

standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed

to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 [Reserved.]

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Economic Load Response Participant resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Economic Load Response Participant resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change

output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator. Market Sellers must specify a ramping rate in the Offer Data that is an accurate representation of the resource's capabilities given the confines of the PJM software.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Synchronized Reserve if its entire output has been designated as emergency energy or if the resource is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary Reserve Requirement and Synchronized Reserve Requirement objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Synchronized Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 10-minute period.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Non-Synchronized Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Non-Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve Requirement for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19A.02 Secondary Reserve.

(a) Secondary Reserve can be supplied from synchronized and non-synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region, as specified in the PJM Manuals. A resource is not eligible to provide Secondary Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market

Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Secondary Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers and Market Sellers offering Secondary Reserve shall comply with applicable standards and requirements for Secondary Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone, as applicable, an amount of Secondary Reserve such that the sum of the Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve meets the respective 30-minute Reserve Requirement for each such Reserve Zone and Reserve Sub-zone, as applicable, and as specified in the PJM Manuals. In accordance with the PJM Manuals, the Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the 30-minute Reserve Requirement in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Secondary Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 30-minute period, minus the increase in energy output or load reduction achievable within a continuous 10-minute period.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market and Secondary Reserve market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Secondary Reserve to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its Markets Gateway tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new Markets Gateway reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of Markets Gateway schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported Markets Gateway

schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve from PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable, and as may be further described in the PJM Manuals.

(b) Market Sellers selling from generation resources and/or Economic Load Response Participant resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Economic Load Response Participant resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Economic Load Response Participant resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Economic Load Response Participant resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Economic Load Response Participant resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the

Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.10 Scheduling.

1.10.1 General.

- (a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.
- (b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.
- (c) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.
- (ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to pay Transmission Congestion Charges and Transmission Loss Charges for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.
- (iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.
- (d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly

energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Operating Agreement, Schedule 1, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection:
(i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed \$2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to \$2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Operating Agreement, Schedule 1, section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source

and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to \$2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs;

(3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour;
- ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour;
- x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:
 - a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1,

section A.2 and the parallel provision of RAA, Schedule 6, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, \$1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and
- iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and

cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be \$0.02/MWh, and for the period from the second month after implementation through the second January 1 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller

has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with

section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response Participant resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator

Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time

Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for \$0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does

not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to section 1.10.9 below or Operating Agreement, Schedule 1, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and

No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Operating Agreement, Schedule 1, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered

and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

(g) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace

such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A above that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated

projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Operating Agreement, Schedule 1, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.5.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Operating Agreement, section 18.17.1, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer

consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (9) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11 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 Economic Load Response Participant 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 Operating Agreement, Schedule 1, 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 Economic Load Response Participant resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant 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 Economic Load Response Participant 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 Economic Load Response Participant 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 energy 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 Economic Load Response Participant 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 Operating Agreement, Schedule 1, 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 available either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant 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. The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market. Resources shall be cleared to provide Synchronized Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Synchronized Reserve offer and the product substitution cost of providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a minimum run

time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Economic Load Response Participant 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 energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources 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 Operating Agreement, Schedule 1, 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 pool-scheduled generation resources as needed to ensure the Primary Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Resources providing Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Non-Synchronized Reserve Market and the Real-time Non-Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Non-Synchronized Reserve Market. Resources eligible to sell Non-Synchronized Reserve shall be cleared to provide Non-Synchronized Reserve on the basis of each resource's product substitution cost between providing Non-Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement.

(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 energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM

Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Operating Agreement, Schedule 1, section 2.4. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the applicable reserve requirements. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any monitored transmission constraints that may exist.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Operating Agreement, Schedule 1, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.

(c) In performing the Real-time Price calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as described in Operating Agreement, Schedule 1, section 2.4 as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative), including Transmission Constraint Penalty Factors, associated with increasing the output of a generation resource or decreasing the consumption by a Demand

Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(d) During the Operating Day, the calculation set forth in Operating Agreement, Schedule 1, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

2.5.1 Declaration of Shortage Pricing

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a 30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage for the purposes of declaring shortage pricing as further described in the PJM Manuals. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, Real-time Prices shall be calculated as described in Operating Agreement, Schedule 1, section 2.5 and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When the Real-time Price software determines that a 30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage exists, whereby the reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the Office of Interconnection shall implement shortage pricing. During shortage pricing, the Real-time Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement consistent with the determination of the clearing price for each reserve product, and the components of Locational Marginal Prices referenced in Operating Agreement, Schedule 1, section 2.5 above shall be calculated as described below. Shortage pricing shall exist until the Real-time Price software program is able to meet the specified reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect.

(b) If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including

but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, the Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized

Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Manual Load Dump Action has been terminated.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Operating Agreement, Schedule 1, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, offers for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. The day-ahead Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is

provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

(b) The Office of the Interconnection shall use its day-ahead market clearing software to forecast if the Office of the Interconnection will experience a shortage of the 30-minute Reserve Requirement, Extended 30-minute Reserve Requirement, the Primary Reserve Requirement, Extended Primary Reserve Requirement, the Synchronized Reserve Requirement, and/or the Extended Synchronized Reserve Requirement, as further described in the PJM Manuals. If the day-ahead market clearing software forecasts that a shortage of any of the reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Day-ahead Locational Marginal Prices consistent with the determination of the clearing price for each reserve product. Shortage pricing shall exist until the day-ahead market clearing software is able to meet the specified reserve requirements.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Operating Agreement, Schedule 1, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region.

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation 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.

$$\text{Regulation Charge} = \text{Hourly Regulation Obligation Share} * (\text{sum of the Real-time Settlement Interval Regulation credits in an hour})$$

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 below, the 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 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Operating Agreement, Schedule 1, section 1.10.1A(e).

(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 Economic Load Response Participant 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 Economic Load Response Participant 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:

$$\text{Accuracy Score} = \max ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

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 Operating Agreement, Schedule 1, section 1.10.1A(e). 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 sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 below do not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Reserve Requirements, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

(b) 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) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve 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 Operating Agreement, Schedule 1, section 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves 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 Operating Agreement, Schedule 1, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Operating Reserves 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 Economic Load Response Participant resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

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 Economic Load Response Participant resources) costs for generation resources.

Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A * B) - C$.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a

Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3(f).
- (ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:
 - 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
 - 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) 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 LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(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 Operating Agreement, Schedule 1, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any

shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, 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 Tariff, Schedule 6A, 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 Operating Agreement, Schedule 1, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (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 Tariff, Schedule 6A.

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) below, 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, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (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 Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared (“Maximum Generation Emergency Alert”); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by section 3.2.3(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as “MaxGen Conditions”). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Operating Agreement, Schedule 1, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. 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:

$$Ramp_Request_t = (Dispatch_target_{t-1} - AOutput_{t-1}) / (LTime_{t-1})$$
$$RL_Desired_t = AOutput_{t-1} + (Ramp_Request_t * Case_Eff_time_{t-1})$$

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. LTime = 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 Response Participant resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Operating Agreement, Schedule 1, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Operating Agreement, Schedule 1, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, 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 exceeds the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges 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 Operating Agreement, Schedule 1, section 3.2.3(h)(ii)(A) 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 Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, 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, Operating Agreement, Schedule 2 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, Operating Agreement, Schedule 2, 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 Operating Agreement, Schedule 1, section 6.4.3. 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's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide..

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve

Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be \$300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's energy expected output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, capped at the amount of Synchronized Reserve the resource responded during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-

time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A] plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B + C + D) - (E + F + G + H)$$

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource, in excess of amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less 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 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately

preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the

difference between (i) the Batch Load Economic Load Response Participant resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes. .

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the

price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement and the Primary Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Primary Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and

the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(\text{zero}) - (A + B + C + D)$$

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price

multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone,

plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirements for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be \$300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the

resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection

requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero,

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time

reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

- (A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;
- (B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;
- (C) A resource's Final Offer is less than its Committed Offer;
- (D) A resource trips offline or otherwise becomes unavailable in real-time;
- (E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or
- (F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B) - (C + D + E + F)$$

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing Secondary Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable,

each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output 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 Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the

Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output 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 Operating Agreement, Schedule 1, 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 Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, 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 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 applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the

end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the 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 Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.6 Emergency Energy.

- (a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at \$850/MWh, provided that the Emergency energy is needed to meet demand in the PJM Region.
- (b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.
- (c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.
- (d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

- (a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.
- (b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market

Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.