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June 4, 2021

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

*Re: PJM Interconnection, L.L.C., Docket No. ER21-2079-000
Revisions to the PJM Operating Agreement and Open Access Transmission Tariff to
Remove the Transmission Loading Relief Buy-Through Options*

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act¹ and the rules and regulations of the Federal Energy Regulatory Commission (“Commission” or “FERC”),² PJM Interconnection, L.L.C. (“PJM”) hereby submits revisions to the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”) and PJM Open Access Transmission Tariff (“Tariff”). The purpose of the proposed revisions is to remove tariff provisions that allow an entity to "buy-through" PJM congestion for certain interchange transactions that PJM would have otherwise curtailed by implementing the transmission loading relief (“TLR”) procedures established by North American Electric Reliability Corporation (“NERC”) and North American Energy Standards Board (“NAESB”). PJM respectfully requests the Commission accept an effective date of August 5, 2021, for the proposed revisions to the Operating Agreement and Tariff submitted herein.

¹ 16 U.S.C. § 824d.

² 18 C.F.R. Part 35.

I. BACKGROUND

In 1999, PJM revised the Operating Agreement and Tariff to provide entities with a voluntary redispatch option that allows an entity to avoid the curtailment of its interchange transactions during a NERC TLR event. The purpose of these provisions was to provide entities with an option to "buy-through" PJM congestion for their interchange transactions between balancing authority areas that use PJM as a flow path, but not the contract path, when PJM otherwise would have curtailed such transactions by implementing the TLR procedures ("TLR Buy-Through Option"). Under this alternative option to curtailing a transaction, if requested by a customer, PJM would refrain from requesting that other reliability coordinators curtail the customer's transactions in the event of a PJM-declared TLR. Instead, PJM would impose congestion charges on the off-the-contract-path transactions causing PJM congestion, if an entity elected this option. To take advantage of this option, an interchange customer was required to notify PJM in advance that it is making this election for the next day. Then, if PJM declared a TLR, instead of asking that a transaction be curtailed, PJM would compute a congestion charge for the off-the-contract-path transaction based on the amount of flow on PJM and differences in locational marginal prices at source and sink points.

The TLR Buy-Through Option has not been used since the effective date of the Operating Agreement and Tariff provisions that contain this redispatch option to the best of PJM's knowledge. Moreover, as discussed below, this option was rendered less useful, if not obsolete, by PJM's decreased reliance on TLRs, and the addition of mandatory NERC reliability standards and NAESB business practice standards pertaining to TLRs that are currently incompatible with the TLR Buy-Through Option.

II. DESCRIPTION OF THE PROPOSED REVISIONS TO THE PJM OPERATING AGREEMENT AND TARIFF

PJM proposes to revise the Operating Agreement and Tariff to remove the TLR Buy-Through Option. To effectuate this option, PJM proposes to delete Operating Agreement, Schedule 1, sections 1.10.6A and 5.1.6, which contain the rules and calculations pertaining to TLR Buy-Through Option, and the identical provisions in the PJM Tariff. PJM also proposes to delete the definition of Transmission Loading Relief Customer from the Operating Agreement and Tariff.

As discussed below, any benefit or value the TLR Buy-Through Option may have once provided or potentially provided no longer exists because of PJM's decreased reliance on TLRs over the years, the creation of mandatory NERC business practice standards and NAESB business practice standards that are incompatible with the TLR Buy-Through Option absent PJM obtaining a regional variation, and a lack of interest in the TLR Buy-Through Option from stakeholders.

At the time the TLR Buy-Through Option provisions of the Operating Agreement and Tariff were implemented in 1999, PJM relied on TLRs to manage congestion to an extent greater than it does today. For multiple reasons, PJM's reliance on and use of TLRs decreased over the years resulting in less need and opportunities to use the TLR Buy-Through Option, which already had little or no demand from customers with interchange transactions.³

First, the integration of a number of utility transmission systems into PJM's operations decreased PJM's reliance on TLR. At the time the Operating Agreement and Tariff provisions for the TLR Buy-Through Option became effective in 1999, PJM's footprint encompassed a five-state region and the systems of numerous utilities. Beginning in 2002, PJM integrated a number of

³ PJM uses redispatch procedures rather than TLRs if possible to manage congestion on the transmission system because, among other reasons, redispatch allows for a far more targeted and effective tool to manage congestion than curtailing interchange transaction through TLR.

additional transmission systems into its operations, which increased the number of generators, transmission, and other internal resources available to PJM to redispatch and manage congestion. Today PJM operates in 13 states and the District of Columbia. This increase in resources allowed PJM to increase its reliance on redispatching internal generation to manage congestion on transmission facilities, which is a more surgical, efficient, and effective tool to manage congestion than curtailing interchange transactions through TLR.⁴ For the same reason, the increase in resources decreased the need for PJM to curtail interchange transactions by issuing TLRs and, as a result, decreased the need for or opportunities to use the TLR Buy-Through Option.

Second, after the effective date of the TLR Buy-Through Option, PJM entered into multiple joint operating agreements (“JOAs”) with neighboring balancing authorities that contain provisions that allow PJM to both proactively and reactively manage congestion with neighbors thereby further decreasing the need to issue TLRs. For example, the JOAs contain provisions that require PJM and its neighbors to proactively coordinate available transfer capability (“ATC”) calculations and limit sales thereof based on the ATC calculations of neighboring balancing authorities. This coordination increases transparency as to each party’s remaining ATC, which helps both parties from selling ATC that may not be available and could result in TLRs.

Similarly, under the market-to-market redispatch provisions of PJM’s JOA, PJM and neighboring balancing authorities’ jointly redispatch generation to alleviate congestion on transmission facilities, which further eliminates the need to issue TLRs. Prior to the implementation of these provisions, as mentioned above, PJM would be required to curtail

⁴ Unlike using TLRs, redispatching generation accounts for the economics of generation. Moreover, TLRs are generally imprecise in matching the congestion relief needed on a particular transmission facility with the interchange transactions that need to be curtailed to provide such relief, which often results in the curtailment of more interchange transactions than needed.

interchange transactions via TLRs if there was insufficient dispatchable generation within PJM to alleviate a constrained facility. Under the market-to-market provisions, PJM may rely on its neighbors' generation to help alleviate congestion on certain transmission facilities and avoid curtailing transactions. In other words, the market-to-market provisions of these JOAs provide PJM with additional generation that is available to redispatch (i.e., the generation of neighboring balancing authorities) prior to issuing a TLR and curtailing transactions.

In addition to the decreased opportunities to use and need for the TLR Buy-Through Option resulting from the decreased use of TLRs, PJM recognized there are several barriers to implementing this option in the unlikely event an entity requested to use this option. Revisions to NAESB business practice standards, NERC reliability standards, PJM's information systems, and the Interchange Distribution Calculator ("IDC") would be needed to effectuate the TLR alternative redispatch product. For example, currently the NERC and NAESB standards do not accommodate excluding tags from the TLR process in the manner required by PJM's TLR product, nor does OATT's implementation of the IDC software. Revisions to these standards (or regional variations to the standards) and systems would be needed to effectuate the buy-through option. However, considering the lack of use of the option, interest in the option, and, as a result, benefit the option provides, the cost of obtaining a regional variation and developing the necessary system changes—assuming such regional variation were granted and system changes were possible—greatly outweigh the benefits the product provides.

Finally, based on discussions with stakeholders and past practice, there is little if any stakeholder support for this voluntary redispatch option. To the best of PJM's knowledge, the TLR Buy-Through Option has never been used since the effective date of this provision in 1999. While PJM cannot state for certain why interchange customers refrained from using this option

PJM's decreased reliance on TLRs is one likely factor for the reasons stated above. Moreover, regardless of past use, current stakeholder support for removing these provisions is strong as demonstrated by the stakeholder vote to remove these provisions. PJM members voted to eliminate the TLR Buy-Through Option from the Operating Agreement and Tariff by acclamation with no objections or abstentions.⁵

The Operating Agreement and Tariff revisions proposed herein are just and reasonable because the TLR Buy-Through Option provides no benefits to the industry; removing the option from the Operating Agreement and Tariff results in little or no costs to PJM, its members, or the industry; and the additional costs system and administrative costs required to implement this option going forward outweigh the benefits the option provides (i.e., costs to coordinate with NERC and NAESB, obtain and effectuate any required regional variations, and implement any required PJM or IDC system changes). As discussed above, this voluntary redispatch option has never been used and any benefit it potentially provided was significantly reduced or rendered obsolete by integrations, JOAs, and the new mandatory, NERC and NAESB rules pertaining to TLRs that did not exist when the buy-through option was implemented. Therefore, deleting this provision will not affect PJM's markets, operations, or current processes for managing congestion.

III. STAKEHOLDER SUPPORT

On March 29, 2021, the PJM Markets and Reliability Committee endorsed by acclamation with no objections and no abstentions the revisions to the Operating Agreement.⁶ On April 21,

⁵ See section III below

⁶ See PJM, PJM Markets and Reliability Committee March 29, 2021 Meeting Minutes, <https://www.pjm.com/-/media/committees-groups/committees/mrc/2021/20210421/20210421-caa-draft-minutes-mrc-20210329.ashx>]

2021, the PJM Members Committee approved by acclamation the proposed revisions to the Operating Agreement with no objections or abstentions.⁷

IV. EFFECTIVE DATE

PJM requests an effective date of August 5, 2021, for the Operating Agreement and Tariff revisions proposed in this filing.

V. DOCUMENTS ENCLOSED

Under PJM encloses the following documents with this transmittal letter:

1. a redlined version of the PJM's proposed revisions to the Operating Agreement and Tariff (Attachment A); and
2. a clean version of the PJM's proposed revisions to the Operating Agreement and Tariff (Attachment B).

VI. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications regarding this filing should be sent to the following individuals:

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⁷ See PJM, PJM Members Committee April 21, 2021 Meeting Minutes, <https://www.pjm.com/-/media/committees-groups/committees/mc/2021/20210503/20210503-item-06a-consent-agenda-draft-minutes-mc-20210421.ashx>.

VII. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM region by posting this filing electronically. In accordance with the Commission's regulations,⁸ PJM will post a copy of this filing to the FERC Filings section of its Web site, located at <http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx>, with a specific link to the newly filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM region⁹ alerting them of the filing and its availability on PJM's website. PJM also serves the parties listed on the Commission's official service list for this docket. Notwithstanding the foregoing, if the document is not immediately available by using the referenced link, it will be available within 24 hours of the filing. A copy of this filing will also be available on the Commission's eLibrary website located at <http://www.ferc.gov/docs-filing/elibrary.asp> in accordance with the Commission's regulations and Order No. 714.

VIII. CONCLUSION

Wherefore, for the foregoing reasons, PJM respectfully requests that the Commission accept the revisions to the PJM Operating Agreement and Tariff proposed herein.

⁸ See 18C.F.R §§ 35.2(e) and 385.2010(f)(3).

⁹ PJM already maintains updates and regularly uses e-mail lists for all PJM members and affected state commissions.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "James M. Burlew". The signature is fluid and cursive, written in a professional style.

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Attachment A

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

(Marked / Redline Format)

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

Definitions – T – U - V

Tangible Net Worth:

“Tangible Net Worth” shall mean total assets less goodwill and other intangible assets, minus total liabilities.

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 Incremental Auction:

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

Third-Party Sale:

“Third-Party Sale” shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

“Tie Line” shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

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 cost-based 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 Net Obligation:

“Total Net Obligation” shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

“Total Net Sell Position” shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

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.

Trade Reference:

“Trade Reference” shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

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 Constraint Penalty Factor:

“Transmission Constraint Penalty Factor” shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

“Transmission Customer” shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

“Transmission Facilities” shall have the meaning set forth in the Operating Agreement.

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 Injection Rights:

“Transmission Injection Rights” shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

“Transmission Interconnection Customer” shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

“Transmission Interconnection Facilities Study” shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

“Transmission Interconnection Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

“Transmission Interconnection Request” shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

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 Loading Relief Customer:**~~

~~“Transmission Loading Relief Customer” shall mean an entity that, in accordance with Operating Agreement, Schedule 1, section 1.10.6A and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.~~

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 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 Attachment Facilities:

“Transmission Owner Attachment Facilities” shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner’s side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

“Transmission Owner Interconnection Facilities” shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner’s side of the Point of Interconnection identified in 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 or interconnected distribution facilities.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall have the same meaning provided in the Operating Agreement.

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.

Transmission Provider:

The “Transmission Provider” shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

- (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
- (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and
- (c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider’s Monthly Transmission System Peak:

“Transmission Provider’s Monthly Transmission System Peak” shall mean the maximum firm usage of the Transmission Provider’s Transmission System in a calendar month.

Transmission Service:

“Transmission Service” shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

“Transmission Service Request” shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

“Transmission System” shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

“Transmission Withdrawal Rights” shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

“Unconstrained LDA Group” shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

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

Unsecured Credit:

“Unsecured Credit” shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

“Unsecured Credit Allowance” shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement’s evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: “Working Credit Limit.”

Updated VRR Curve:

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

Updated VRR Curve Decrement:

“Updated VRR Curve Decrement” shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

“Updated VRR Curve Increment” shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net

Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

“Upgrade Construction Service Agreement” shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

“Upgrade Customer” shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

“Upgrade Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

“Upgrade-Related Rights” shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

“Upgrade Request” shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

“Up-to Congestion Counterflow Transaction” shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month’s

average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

“Up-to Congestion Historical Month” shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an “Up-to Congestion Prevailing Flow Transaction” if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

“Up-to Congestion Reference Price” for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

- For Up-to Congestion Prevailing Flow Transactions: 30th percentile
- For Up-to Congestion Counterflow Transactions when bid: 20th percentile
- For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

“Up-to Congestion Transaction” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

“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.

Variable Resource Requirement Curve:

“Variable Resource Requirement Curve” shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

“Virtual Credit Exposure” shall mean the amount of potential credit exposure created by a market participant’s bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

“Virtual Transaction” shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

“Virtual Transaction Screening” shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

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

Voltage Reduction Action:

“Voltage Reduction Action” shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

“Voltage Reduction Alert” shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

“Voltage Reduction Warning” shall mean a notification from PJM to warn Members that PJM’s available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

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 was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. 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 have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, 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 have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or *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; and

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; and

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, \$1,849/megawatt-hour;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,425/megawatt hour; 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 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 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.

(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 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.

(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, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(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.*

1.10.4 Capacity Resources.

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

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance

with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

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.

~~1.10.6A Transmission Loading Relief Customers.~~

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

~~(i) — enter its election on OASIS by 11:00 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and~~

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

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

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

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A 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 an 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 of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the 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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the 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*. 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 10:00 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.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

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

If a dollar-per-MW-hour value is applied in a calculation under this section 5.1 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.

5.1.2 General.

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

5.1.3 Network Service User and Market Participant Calculations.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges.

(b) For each Day-ahead Settlement Interval, Market Participants shall be charged for transmission congestion resulting from all Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which both the Market Participant withdraws energy and such energy is priced.

(c) For each Day-ahead Settlement Interval, Market Participants shall be reimbursed for transmission congestion resulting from all Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which the Market Participant injects energy and such energy is priced.

(d) The day-ahead component of a Market Participant's Transmission Congestion Charge is equal to the difference between the total day-ahead transmission congestion withdrawal charge calculated in subsection (b) and the total day-ahead transmission congestion injection credit calculated in subsection (c).

(e) (i) The amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For

each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(ii) To determine the amount of load served by each LSE in an Electric Distributor's territory, PJM Settlement utilizes the information submitted into PJM's internal energy scheduling tool by LSEs and Electric Distributors for their respective load settlements ("load contract"), including the names of the LSE responsible for serving the load and the Electric Distributor in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the Energy Settlement Area at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified Energy Settlement Area is further assigned to individual load buses included in the Energy Settlement Area, based on the definition for the Energy Settlement Area as defined in Section 31.7 of the PJM Tariff, which specifies the percentage of the Energy Settlement Area that each bus represents, to identify the LSE's hourly megawatts of load at each bus. All megawatts of load assigned to LSEs in an Electric Distributor's territory as described herein are subtracted from the total megawatts of load for which the Electric Distributor is responsible as determined in subsection (e)(i) above.

(iii) Electric Distributors that hold Provider of Last Resort ("POLR") auctions or similar load auctions may direct PJM to automatically assign megawatt hours for which the Electric Distributor is responsible, as determined in subsection (e)(ii) above, to the LSEs whose bids were accepted in the auction ("POLR Suppliers") based on the tranches the POLR Suppliers won in the auction, as a billing service, based on their contracts associated with the POLR load programs. In such case, the POLR Supplier's share of load shall be determined by multiplying the megawatt hours at each bus that were not specifically assigned under load contracts by the percentage of load won by the POLR Supplier in proportion to its share of the total POLR load of the Electric Distributor. This billing service may also apply to Electric Distributors and LSEs that mutually agree upon a transfer of load from the EDC to the LSE based upon a specified percentage of the megawatt hours at each bus that were not specifically assigned under load contracts.

(f) For each Real-time Settlement Interval, Market Participants shall be assessed for Transmission Congestion Charges (positive or negative) in accordance with the following equation:

$$[(A - B) * C] - [(D - E) * C]$$

Where:

A = The Market Participant Energy Withdrawal megawatts in real-time at the location at which both the Market Participant withdraws energy and such energy is priced;

B = The Market Participant Energy Withdrawal megawatts in day-ahead at the location at which both the Market Participant withdraws energy and such energy is priced;

C = Real-time Congestion Price;

D = The Market Participant Energy Injection megawatts in real-time at the location at which both the Market Participant injects energy and such energy is priced; and

E = The Market Participant Energy Injection megawatts in day-ahead at the location at which both the Market Participant injects energy and such energy is priced.

- (g) 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 Transmission Congestion Charges under subsection (f).

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy using such Transmission Service.

- (a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.
- (b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. For each Real-time Settlement Interval, a Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

5.1.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy on the scheduled path.

- (a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for the transaction MWh scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point.
- (b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time MWh in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time MWh falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. 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 transactions used to calculate Transmission Congestion Charges under this subsection (b).

5.1.5 Operating Margin Customer Calculation.

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

~~5.1.6 Transmission Loading Relief Customer Calculation.~~

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

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

~~————(c)—— The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program. Reserved.~~

5.1.7 Reserved.

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

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 Loading Relief Customer:**~~

~~“Transmission Loading Relief Customer” shall mean an entity that, in accordance with Operating Agreement, Schedule 1, section 1.10.6A and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.~~

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.

1.10 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 provisions 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 provisions 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 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, \$1,849/megawatt-hour;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,425/megawatt-hour; 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 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 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.

(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 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.

(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 dispatched 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.

~~1.10.6A — Transmission Loading Relief Customers.~~

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

- ~~(i) — enter its election on OASIS by 11:00 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and~~
- ~~(ii) — if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly~~

~~integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.~~

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

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

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A 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 an 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 of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the 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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the 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*. 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.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

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

If a dollar-per-MW-hour value is applied in a calculation under this section 5.1 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.

5.1.2 General.

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

5.1.3 Network Service User and Market Participant Calculations.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges.

(b) For each Day-ahead Settlement Interval, Market Participants shall be charged for transmission congestion resulting from all Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which both the Market Participant withdraws energy and such energy is priced.

(c) For each Day-ahead Settlement Interval, Market Participants shall be reimbursed for transmission congestion resulting from all Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which the Market Participant injects energy and such energy is priced.

(d) The day-ahead component of a Market Participant's Transmission Congestion Charge is equal to the difference between the total day-ahead transmission congestion withdrawal charge calculated in subsection (b) and the total day-ahead transmission congestion injection credit calculated in subsection (c).

(e) (i) The amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For

each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(ii) To determine the amount of load served by each LSE in an Electric Distributor's territory, PJM Settlement utilizes the information submitted into PJM's internal energy scheduling tool by LSEs and Electric Distributors for their respective load settlements ("load contract"), including the names of the LSE responsible for serving the load and the Electric Distributor in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the Energy Settlement Area at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified Energy Settlement Area is further assigned to individual load buses included in the Energy Settlement Area, based on the definition for the Energy Settlement Area as defined in Section 31.7 of the PJM Tariff, which specifies the percentage of the Energy Settlement Area that each bus represents, to identify the LSE's hourly megawatts of load at each bus. All megawatts of load assigned to LSEs in an Electric Distributor's territory as described herein are subtracted from the total megawatts of load for which the Electric Distributor is responsible as determined in subsection (e)(i) above.

(iii) Electric Distributors that hold Provider of Last Resort ("POLR") auctions or similar load auctions may direct PJM to automatically assign megawatt hours for which the Electric Distributor is responsible, as determined in subsection (e)(ii) above, to the LSEs whose bids were accepted in the auction ("POLR Suppliers") based on the tranches the POLR Suppliers won in the auction, as a billing service, based on their contracts associated with the POLR load programs. In such case, the POLR Supplier's share of load shall be determined by multiplying the megawatt hours at each bus that were not specifically assigned under load contracts by the percentage of load won by the POLR Supplier in proportion to its share of the total POLR load of the Electric Distributor. This billing service may also apply to Electric Distributors and LSEs that mutually agree upon a transfer of load from the EDC to the LSE based upon a specified percentage of the megawatt hours at each bus that were not specifically assigned under load contracts.

(f) For each Real-time Settlement Interval, Market Participants shall be assessed for Transmission Congestion Charges (positive or negative) in accordance with the following equation:

$$[(A - B) * C] - [(D - E) * C]$$

Where:

A = The Market Participant Energy Withdrawal megawatts in real-time at the location at which both the Market Participant withdraws energy and such energy is priced;

B = The Market Participant Energy Withdrawal megawatts in day-ahead at the location at which both the Market Participant withdraws energy and such energy is priced;

C = Real-time Congestion Price;

D = The Market Participant Energy Injection megawatts in real-time at the location at which both the Market Participant injects energy and such energy is priced; and

E = The Market Participant Energy Injection megawatts in day-ahead at the location at which both the Market Participant injects energy and such energy is priced.

- (g) 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 Transmission Congestion Charges under subsection (f).

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy using such Transmission Service.

- (a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.
- (b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. For each Real-time Settlement Interval, a Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

5.1.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy on the scheduled path.

- (a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for the transaction MWh scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point.
- (b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time MWh in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time MWh falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. 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 transactions used to calculate Transmission Congestion Charges under this subsection (b).

5.1.5 Operating Margin Customer Calculation.

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

~~5.1.6 Transmission Loading Relief Customer Calculation.~~

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

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

~~————(c)—— The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program. **Reserved.**~~

5.1.7 Reserved.

Attachment B

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

(Clean Format)

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

Definitions – T – U - V

Tangible Net Worth:

“Tangible Net Worth” shall mean total assets less goodwill and other intangible assets, minus total liabilities.

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 Incremental Auction:

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

Third-Party Sale:

“Third-Party Sale” shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

“Tie Line” shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

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 cost-based 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 Net Obligation:

“Total Net Obligation” shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

“Total Net Sell Position” shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

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.

Trade Reference:

“Trade Reference” shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

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 Constraint Penalty Factor:

“Transmission Constraint Penalty Factor” shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

“Transmission Customer” shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

“Transmission Facilities” shall have the meaning set forth in the Operating Agreement.

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 Injection Rights:

“Transmission Injection Rights” shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

“Transmission Interconnection Customer” shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

“Transmission Interconnection Facilities Study” shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

“Transmission Interconnection Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

“Transmission Interconnection Request” shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

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 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 Attachment Facilities:

“Transmission Owner Attachment Facilities” shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner’s side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

“Transmission Owner Interconnection Facilities” shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner’s side of the Point of Interconnection identified in 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 or interconnected distribution facilities.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall have the same meaning provided in the Operating Agreement.

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.

Transmission Provider:

The “Transmission Provider” shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

- (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
- (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider’s Monthly Transmission System Peak:

“Transmission Provider’s Monthly Transmission System Peak” shall mean the maximum firm usage of the Transmission Provider’s Transmission System in a calendar month.

Transmission Service:

“Transmission Service” shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

“Transmission Service Request” shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

“Transmission System” shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

“Transmission Withdrawal Rights” shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

“Unconstrained LDA Group” shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

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

Unsecured Credit:

“Unsecured Credit” shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

“Unsecured Credit Allowance” shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement’s evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: “Working Credit Limit.”

Updated VRR Curve:

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

Updated VRR Curve Decrement:

“Updated VRR Curve Decrement” shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

“Updated VRR Curve Increment” shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

“Upgrade Construction Service Agreement” shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

“Upgrade Customer” shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

“Upgrade Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

“Upgrade-Related Rights” shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

“Upgrade Request” shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

“Up-to Congestion Counterflow Transaction” shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month’s average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

“Up-to Congestion Historical Month” shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an “Up-to Congestion Prevailing Flow Transaction” if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

“Up-to Congestion Reference Price” for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

- For Up-to Congestion Prevailing Flow Transactions: 30th percentile
- For Up-to Congestion Counterflow Transactions when bid: 20th percentile
- For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

“Up-to Congestion Transaction” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

“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.

Variable Resource Requirement Curve:

“Variable Resource Requirement Curve” shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

“Virtual Credit Exposure” shall mean the amount of potential credit exposure created by a market participant’s bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

“Virtual Transaction” shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

“Virtual Transaction Screening” shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

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

Voltage Reduction Action:

“Voltage Reduction Action” shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

“Voltage Reduction Alert” shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

“Voltage Reduction Warning” shall mean a notification from PJM to warn Members that PJM’s available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

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 was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. 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 have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, 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 have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or *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; and

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; and

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, \$1,849/megawatt-hour;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,425/megawatt hour; 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 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 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.

(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 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.

(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, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(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.*

1.10.4 Capacity Resources.

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

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance

with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

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 an 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 of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the 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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the 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*. 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 10:00 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.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

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

If a dollar-per-MW-hour value is applied in a calculation under this section 5.1 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.

5.1.2 General.

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

5.1.3 Network Service User and Market Participant Calculations.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges.

(b) For each Day-ahead Settlement Interval, Market Participants shall be charged for transmission congestion resulting from all Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which both the Market Participant withdraws energy and such energy is priced.

(c) For each Day-ahead Settlement Interval, Market Participants shall be reimbursed for transmission congestion resulting from all Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which the Market Participant injects energy and such energy is priced.

(d) The day-ahead component of a Market Participant's Transmission Congestion Charge is equal to the difference between the total day-ahead transmission congestion withdrawal charge calculated in subsection (b) and the total day-ahead transmission congestion injection credit calculated in subsection (c).

(e) (i) The amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For

each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(ii) To determine the amount of load served by each LSE in an Electric Distributor's territory, PJM Settlement utilizes the information submitted into PJM's internal energy scheduling tool by LSEs and Electric Distributors for their respective load settlements ("load contract"), including the names of the LSE responsible for serving the load and the Electric Distributor in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the Energy Settlement Area at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified Energy Settlement Area is further assigned to individual load buses included in the Energy Settlement Area, based on the definition for the Energy Settlement Area as defined in Section 31.7 of the PJM Tariff, which specifies the percentage of the Energy Settlement Area that each bus represents, to identify the LSE's hourly megawatts of load at each bus. All megawatts of load assigned to LSEs in an Electric Distributor's territory as described herein are subtracted from the total megawatts of load for which the Electric Distributor is responsible as determined in subsection (e)(i) above.

(iii) Electric Distributors that hold Provider of Last Resort ("POLR") auctions or similar load auctions may direct PJM to automatically assign megawatt hours for which the Electric Distributor is responsible, as determined in subsection (e)(ii) above, to the LSEs whose bids were accepted in the auction ("POLR Suppliers") based on the tranches the POLR Suppliers won in the auction, as a billing service, based on their contracts associated with the POLR load programs. In such case, the POLR Supplier's share of load shall be determined by multiplying the megawatt hours at each bus that were not specifically assigned under load contracts by the percentage of load won by the POLR Supplier in proportion to its share of the total POLR load of the Electric Distributor. This billing service may also apply to Electric Distributors and LSEs that mutually agree upon a transfer of load from the EDC to the LSE based upon a specified percentage of the megawatt hours at each bus that were not specifically assigned under load contracts.

(f) For each Real-time Settlement Interval, Market Participants shall be assessed for Transmission Congestion Charges (positive or negative) in accordance with the following equation:

$$[(A - B) * C] - [(D - E) * C]$$

Where:

A = The Market Participant Energy Withdrawal megawatts in real-time at the location at which both the Market Participant withdraws energy and such energy is priced;

B = The Market Participant Energy Withdrawal megawatts in day-ahead at the location at which both the Market Participant withdraws energy and such energy is priced;

C = Real-time Congestion Price;

D = The Market Participant Energy Injection megawatts in real-time at the location at which both the Market Participant injects energy and such energy is priced; and

E = The Market Participant Energy Injection megawatts in day-ahead at the location at which both the Market Participant injects energy and such energy is priced.

- (g) 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 Transmission Congestion Charges under subsection (f).

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy using such Transmission Service.

- (a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.
- (b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. For each Real-time Settlement Interval, a Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

5.1.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy on the scheduled path.

- (a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for the transaction MWh scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point.
- (b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time MWh in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time MWh falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. 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 transactions used to calculate Transmission Congestion Charges under this subsection (b).

5.1.5 Operating Margin Customer Calculation.

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

5.1.6 Reserved.

5.1.7 Reserved.

Section(s) of the
PJM Operating Agreement
(Clean Format)

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.

1.10 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 provisions 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 provisions 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 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, \$1,849/megawatt-hour;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,425/megawatt-hour; 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 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 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.

(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 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.

(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 dispatched 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 an 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 of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the 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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the 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*. 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.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

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

If a dollar-per-MW-hour value is applied in a calculation under this section 5.1 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.

5.1.2 General.

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

5.1.3 Network Service User and Market Participant Calculations.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges.

(b) For each Day-ahead Settlement Interval, Market Participants shall be charged for transmission congestion resulting from all Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which both the Market Participant withdraws energy and such energy is priced.

(c) For each Day-ahead Settlement Interval, Market Participants shall be reimbursed for transmission congestion resulting from all Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which the Market Participant injects energy and such energy is priced.

(d) The day-ahead component of a Market Participant's Transmission Congestion Charge is equal to the difference between the total day-ahead transmission congestion withdrawal charge calculated in subsection (b) and the total day-ahead transmission congestion injection credit calculated in subsection (c).

(e) (i) The amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For

each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(ii) To determine the amount of load served by each LSE in an Electric Distributor's territory, PJM Settlement utilizes the information submitted into PJM's internal energy scheduling tool by LSEs and Electric Distributors for their respective load settlements ("load contract"), including the names of the LSE responsible for serving the load and the Electric Distributor in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the Energy Settlement Area at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified Energy Settlement Area is further assigned to individual load buses included in the Energy Settlement Area, based on the definition for the Energy Settlement Area as defined in Section 31.7 of the PJM Tariff, which specifies the percentage of the Energy Settlement Area that each bus represents, to identify the LSE's hourly megawatts of load at each bus. All megawatts of load assigned to LSEs in an Electric Distributor's territory as described herein are subtracted from the total megawatts of load for which the Electric Distributor is responsible as determined in subsection (e)(i) above.

(iii) Electric Distributors that hold Provider of Last Resort ("POLR") auctions or similar load auctions may direct PJM to automatically assign megawatt hours for which the Electric Distributor is responsible, as determined in subsection (e)(ii) above, to the LSEs whose bids were accepted in the auction ("POLR Suppliers") based on the tranches the POLR Suppliers won in the auction, as a billing service, based on their contracts associated with the POLR load programs. In such case, the POLR Supplier's share of load shall be determined by multiplying the megawatt hours at each bus that were not specifically assigned under load contracts by the percentage of load won by the POLR Supplier in proportion to its share of the total POLR load of the Electric Distributor. This billing service may also apply to Electric Distributors and LSEs that mutually agree upon a transfer of load from the EDC to the LSE based upon a specified percentage of the megawatt hours at each bus that were not specifically assigned under load contracts.

(f) For each Real-time Settlement Interval, Market Participants shall be assessed for Transmission Congestion Charges (positive or negative) in accordance with the following equation:

$$[(A - B) * C] - [(D - E) * C]$$

Where:

A = The Market Participant Energy Withdrawal megawatts in real-time at the location at which both the Market Participant withdraws energy and such energy is priced;

B = The Market Participant Energy Withdrawal megawatts in day-ahead at the location at which both the Market Participant withdraws energy and such energy is priced;

C = Real-time Congestion Price;

D = The Market Participant Energy Injection megawatts in real-time at the location at which both the Market Participant injects energy and such energy is priced; and

E = The Market Participant Energy Injection megawatts in day-ahead at the location at which both the Market Participant injects energy and such energy is priced.

- (g) 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 Transmission Congestion Charges under subsection (f).

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy using such Transmission Service.

- (a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.
- (b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. For each Real-time Settlement Interval, a Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

5.1.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy on the scheduled path.

- (a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for the transaction MWh scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point.
- (b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time MWh in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time MWh falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. 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 transactions used to calculate Transmission Congestion Charges under this subsection (b).

5.1.5 Operating Margin Customer Calculation.

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

5.1.6 Reserved.

5.1.7 Reserved.