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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. ER15-1849-000

Dear Ms. Bose:

Pursuant to section 205 of the Federal Power Act (“FPA”), 16 U.S.C. § 824d, and the Federal Energy Regulatory Commission’s (“Commission”) regulations, 18 C.F.R. Part 35, PJM Interconnection, L.L.C. (“PJM”) hereby submits revisions to the PJM Open Access Transmission Tariff (“Tariff”), Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”) and Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (“RAA”) to improve the measurement and verification procedures for Curtailment Service Providers¹ (“CSP”) with residential customers providing demand response (“residential DR customers”) in the Day-ahead Energy Market, Real-time Energy Market, Reliability Pricing Model (“RPM”) capacity market and Synchronized Reserve market. PJM requests that the Commission issue an order by no later than August 3, 2015, with an effective date of August 3, 2015, for the proposed revisions in accordance with the 60-day notice requirement in section 35.3(a)(1) of the Commission’s Regulations, 18 C.F.R. Part 35.

PJM is mindful of the uncertainty associated with demand response in wholesale electric markets engendered by the litigation resulting from United States Court of Appeals for the

¹ All capitalized terms that are not otherwise defined herein shall have the same meaning as they are defined in the Tariff, Operating Agreement, and RAA.

District of Columbia’s (“D.C. Circuit”) *Electric Power Supply Ass’n v. FERC* (“*EPSA*”)² decision. However, as further discussed below, the reforms proposed herein, which were adopted by acclamation by PJM’s stakeholders, are appropriate and relevant and should be implemented regardless of any uncertainty caused by the *EPSA* decision. PJM is therefore requesting that the Commission act on this filing without regard to the *EPSA* appeal.

Moreover, while preparing this filing letter, PJM staff recognized that certain references to “PJM Interchange Energy Market” and associated terms in PJM’s governing documents may need to be clarified in several sections that pertain to its demand response programs because such terms, as they are used in these sections, are potentially ambiguous. Given that these clarifying changes are needed not only in sections that are proposed in this filing, but also in several sections that are not affected by this filing, PJM is not proposing such clarifying revisions at this time. Instead, PJM intends to work with its stakeholders to come to an agreement on the necessary clarifying revisions and submit the changes in a future filing. In the meantime, any potential ambiguities in the governing document provisions will continue to be informed by the greater details provided in PJM Manual 11, which describes, among other topics, participation by demand response providers in PJM’s markets.³

I. BACKGROUND

a. General Background

CSPs have had residential customers in their portfolios participating in PJM’s demand response programs for nearly twenty years, and the role of these customers and their importance has evolved over that time. However, the procedures currently used by PJM to measure and

² *Electric Power Supply Ass’n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014)

³ See PJM Manual 11: Energy & Ancillary Services Market Operations, Version 75 (April 9, 2015), available at <http://www.pjm.com/documents/manuals.aspx>.

verify the amount of load reduction provided by some residential DR customers are outdated. While these procedures have provided reasonable estimates of those customers' ability to reduce load, improvements in technology and greater sophistication among residential DR customers now allow for more accurate measurement and verification procedures at relatively small costs to affected parties. These improved procedures are just and reasonable because they will better reflect the actual amount of load reduction provided by these residential DR customers to CSPs participating in PJM's demand response programs, and will enable PJM to more effectively operate the bulk electric system.

b. Demand Response Based on Residential Customer Load Reduction

Residential customers, similar to the majority of commercial and industrial customers, may not directly provide demand response in PJM's markets but instead must participate through a CSP. Consequently, PJM does not directly interact with residential customers, but instead works with the CSP, which is a PJM Member, and is the entity responsible for providing PJM with all data relevant to the measurement and verification of any load reductions provided to the CSP by residential customers.

PJM measures compliance⁴ for Demand Resources participating in RPM using one of three methods: 1) direct load control (now proposed to be referred to as "Legacy Direct Load Control") ("LDLC")⁵; 2) firm service level ("FSL"); 3) and guaranteed load drop ("GLD").⁶

⁴ PJM considers "compliance" to be a subcategory of its more general measurement and verification processes.

⁵ See OATT ATTACHMENT DD-1. Attachment DD-1 of the Tariff is identical to Schedule 6 of the RAA. For convenience, where PJM refers herein to proposed revisions to Attachment DD-1 of the Tariff, those references also are intended to encompass the identical proposed revisions to the corresponding provisions of Schedule 6 of the RAA.

⁶ See Tariff, Attachment DD-1, section G.

Residential DR customer electricity usage is typically reduced through Direct Load Control⁷ technology by the CSP, and can be either interval metered or non-interval metered.⁸ For interval metered residential DR customers, CSPs use such customers' actual meter data to measure the amount of load reductions being provided by these customers, and utilize the FSL or GLD methods to measure compliance. This approach is consistent with the way load reductions are measured and verified for commercial and industrial customers.

For the past five years, non-interval metered residential DR customers have participated in the Day-ahead Energy Market, Real-time Energy Market and RPM through the Non-Hourly Metered Customer Pilot ("Pilot Program").⁹ For non-interval metered residential DR customers participating in RPM, CSPs have typically utilized LDLC as their compliance method.¹⁰ Rather than submitting actual meter data for this class of customers, CSPs instead have been permitted to submit a load research study supporting the performance of each residential customer, or utilize the base per-residential customer impacts contained in the "Deemed Savings Report"¹¹ provided by PJM to approximate the amount of load reduction contributed by non-interval

⁷ See OATT Definitions – C-D; OA Definitions C – D. As described further in section II.A, Direct Load Control is a type of technology used by CSPs to reduce the output of residential DR customers. Residential DR customers referred to herein should be assumed to be operated using Direct Load Control technology.

⁸ Interval metered customers are customers equipped with meters that measure consumption of energy on an hourly or sub-hourly basis. See Tariff, Attachment K-Appendix, section 1.5A.4 (a). Attachment K-Appendix of the Tariff and Schedule 1 of the Operating Agreement are identical. For convenience, where PJM refers herein to proposed revisions to Attachment K-Appendix of the Tariff, those references also are intended to encompass the identical proposed revisions to the corresponding provisions of Schedule 1 of the Operating Agreement.

⁹ Section 1.5A.7 of Attachment K-Appendix of the Tariff describes the Pilot Program. As described further below in section I.c, non-interval metered residential DR customers have also participated in the Synchronized Reserve market through out-of-market trial programs.

¹⁰ Non-interval metered residential DR customers participating in the Day-ahead Energy Market, Real-time Energy Market and Synchronized Reserve market have utilized multiple compliance methods when participating in the Pilot Program.

¹¹ The Deemed Savings Report is available at <http://www.pjm.com/~media/documents/reports/20070406-deemed-savings-report-ac-heat.ashx>.

metered residential DR customers. If CSPs use the load research study, they have also been required to conduct a switch operability study once every five years. This study determines how many devices providing load reduction (primarily air conditioners) receive dispatch instructions from the CSP, and are correspondingly cycled¹² to reduce electrical consumption of the device. The combined per participant impact from the load research study and the switch operability study are used by the CSP to determine applicable load reduction impacts from non-interval metered residential DR customers.

These methods utilize past performance to estimate a non-interval metered residential customer's actual load reduction during an event, and were created when interval metering and associated load data management were cost prohibitive, utilized outdated technology,¹³ and only a handful of legacy utility based programs were in effect. However, the assumptions relied upon in these methods can easily become outdated and not reflect the actual ability of current residential DR customers to provide load reductions. Further, these estimates do not account for any changes in how electricity demand for residential DR customers are managed by CSPs, particularly with regard to the more advanced technologies utilized today by CSPs. Moreover, these backward-looking methods assume every customer will be cycled the same way with the same technology for the duration of the Delivery Year. This does not allow the CSP to make modifications to how electricity consumption is reduced based on its experience and actual need during the Delivery Year.

¹² The term "cycling" describes the process of turning a device on and off.

¹³ For example, CSPs participating in older LDLC programs employed radio frequency technologies to control air conditioners at the same time. This is unsophisticated technology compared to some of the smart grid thermostat technologies and associated software that have been deployed in recent years.

c. Proposed Solution

In order to improve the accuracy of measuring and verifying load reductions of CSPs that are provided by non-interval metered residential DR customers, PJM is proposing revisions that will effectively eliminate the LDLC compliance method for such Demand Resources in RPM by June 1, 2016, and eliminate the use of the Deemed Savings Report, load research studies and associated switch operability studies for CSPs measuring and verifying performance of non-interval metered residential DR customers in the Day-ahead Energy Market, Real-time Energy Market and Synchronized Reserve market. Instead, CSPs that have registered non-interval metered residential DR customers comprising a portion of their demand response portfolios will be required to use current statistical samples of interval metered residential DR customers to approximate their performance.¹⁴ If such statistical samples are used, PJM will permit non-interval metered residential DR customers to participate fully in the Day-ahead Energy Market, Real-time Energy Market, RPM and Synchronized Reserve market through a CSP.

For the past five years, PJM has used statistical samples based on current data when measuring non-interval metered residential DR customers' performance that have participated in the Day-ahead Energy Market, Real-time Energy Market and RPM through the Pilot Program and in the Synchronized Reserve market (but not any other Ancillary Services markets) through out-of-market trial programs. These out-of-market trial programs are conducted by PJM's Applied Solutions Department and do not result in payments to participants in these trials. PJM

¹⁴ The interval metered customers used as a proxy sample population for the non-interval metered customers must be representative of the non-interval metered customers. Full technical details related to statistical sampling will be appropriately contained in PJM Manual 19: Load Forecasting and Analysis, Version 27 (March 26, 2015), available at <http://www.pjm.com/documents/manuals.aspx>. ("PJM Manual 19").

routinely utilizes these trial programs to test different technologies before they operate in PJM's markets, and they are distinct from the Pilot Program.

This experience has proven to PJM that measurements based on statistical sampling are more accurate than those based on the more static analytical methods currently employed for measurement and verification and compliance, and PJM believes it is just and reasonable to require all non-interval metered residential DR customers to be measured and verified using current statistical sampling when they participate in the Day-ahead Energy Market, Real-time Energy Market, RPM and Synchronized Reserve market through a CSP. This is particularly true given that in many areas within PJM's footprint, interval meters are widely used, and therefore utilizing samples based on existing interval meters is easy to implement. In other areas where interval meters are not widely used, the cost of interval meters has fallen drastically in recent years, meaning that the costs of installing some interval meters by some Market Participants to provide statistical samples are far outweighed by the greater accuracy that they are able to provide to PJM.

As described in detail below, PJM is proposing a transition provision for implementing statistical sampling for CSPs. CSPs will be eligible for the transition provision if they have RPM obligations for future Delivery Years based on non-interval metered residential DR customer load reduction commitments and are unable to implement statistical sampling, or may have their estimated load reductions decreased as a result of statistical sampling. Additionally, PJM is proposing revisions that align several sections of the Tariff, Operating Agreement and RAA with the revisions related to statistical sampling. PJM is also taking this opportunity to make other clarifying revisions to the governing documents related to its demand response programs as discussed in detail below.

d. Uncertainty Related To EPSA

Despite the fact that the *EPSA* decision has created uncertainty related to the future of demand response in wholesale electric markets, PJM believes that it is prudent to move forward with the proposed revisions at this time. The mandate enforcing the *EPSA* decision has been stayed pending the Supreme Court's resolution of the *EPSA* appeal, and the Supreme Court recently granted a *writ of certiorari* to hear the appeal.¹⁵ It is likely that the Supreme Court will not issue a decision on the *EPSA* appeal until the spring of 2016 at the earliest, and it is possible that a final disposition of this issue could take longer if the case is remanded to the D.C. Circuit for further consideration after the Supreme Court issues its opinion. In the meantime, CSPs continue to utilize load reductions from residential DR customers when participating in PJM's markets. Thus, it is prudent for PJM to move forward with administering these markets under the current regulatory and legal construct until (and if) such construct changes. The Commission recently approved revisions in ISO New England Inc.'s tariff related to demand response despite the uncertainty of *EPSA*,¹⁶ and PJM accordingly requests that the Commission's decision in this proceeding not be delayed or influenced by any uncertainty that has been caused by the *EPSA* decision and appeal process.

II. DESCRIPTION OF TARIFF REVISIONS

a. Definition of Direct Load Control

¹⁵ FERC v. Electric Power Supply, et al., No. 14-840 (U.S. May 4, 2015) (order granting *certiorari*).

¹⁶ See *ISO New England Inc., New England Power Pool Participants Committee*, 150 FERC ¶ 61,007, at P 29 (2015) ("While we acknowledge that the *EPSA* decision creates uncertainty for demand response resources in FERC-jurisdictional wholesale markets, we find it appropriate at this time to proceed with these market enhancements until further action is taken.").

PJM is proposing to add a defined term Direct Load Control to the Tariff and Operating Agreement to describe the type of technology used by the CSP to control its customers' load reductions through its market operations center or its agent in response to PJM instructions.¹⁷ The term Direct Load Control is currently used in PJM's governing agreements, but the term does not refer to the type of technology used to control load reductions, but rather pertains to the compliance procedure that has historically been used by CSPs participating in RPM to measure compliance for its residential DR customers. This compliance method is described in detail in section G of Attachment DD-1 of the Tariff. In order to distinguish the compliance procedure from the type of technology used to control load reductions, PJM is proposing a new defined term Legacy Direct Load Control to describe the compliance procedure,¹⁸ and changing all relevant references from Direct Load Control to Legacy Direct Load Control throughout the governing documents. By adding a definition for Direct Load Control to describe the load reduction technology, and adding the new definition of Legacy Direct Load Control to describe the compliance method, PJM intends to clarify the difference between these two terms.

b. Revisions Related to Establishing Statistical Sampling

PJM is proposing revisions to several sections of its governing documents that make appropriate references to statistical sampling for CSPs that have demand response portfolios at least partially comprised of load reductions from non-interval metered residential DR customers. The precise technical details related to how the real-time statistical samplings are to be performed will be appropriately added to PJM Manual 19. The following sections of the Tariff

¹⁷ See OATT Definitions – C-D; OA Definitions C – D.

¹⁸ See OATT ATTACHMENT DD-1.

and Operating Agreement are being revised as described below to incorporate statistical sampling for non-interval metered residential DR customers.

First, PJM is proposing to revise section 1.5A.1 of Attachment K-Appendix of the Tariff as follows:

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction, may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of Section 1.5A.10.¹⁹

These proposed revisions enable CSPs that have non-interval metered residential Direct Load Control customers to qualify as Economic Load Response Participants if those customers are metered using a statistical sample of electric distribution company accounts, as will be further described in PJM Manual 19. The revisions are necessary because as previously discussed, CSPs with non-interval metered residential DR customers as part of their demand response portfolios have only participated in the Day-ahead Energy Market, Real-time Energy

¹⁹ See OATT ATT K APPX Sec 1.5A. As described in the proposed revisions, statistical sampling utilizes current data. The language in this section referencing “current data” was added by PJM staff after stakeholders endorsed the proposed revisions in this filing. This revision is being added for clarity to explicitly state that statistical sampling is based on current data, and does not alter the substance of PJM’s proposal as it was endorsed by stakeholders. PJM is making similar revisions to sections 3.3A.1, 8.3, 8.11 of Attachment K-Appendix of the Tariff.

Market and RPM through the Pilot Program, and in the Synchronized Reserve market through the previously described out-of-market trial programs.

Further, the provisions that will be added to the PJM Manuals and referenced in the proposed Tariff revisions will specify in detail that CSPs with non-interval metered residential DR customers with statistical sampling are allowed to participate in the Synchronized Reserve market only, and not in other Ancillary Services markets. PJM is allowing these customers to participate in its Synchronized Reserve market through a CSP because their performance in the trial programs demonstrated that such customers could effectively and accurately respond to PJM's dispatch signals used to operate the Synchronized Reserve market in real-time. These customers did not participate in any other Ancillary Services markets through the trial programs, and therefore PJM is not permitting their participation in any other Ancillary Services market at this time. While the proposed revisions to section 1.5A.1 will allow non-interval metered residential DR customers to fully participate in the Day-ahead Energy Market, Real-time Energy Market and Synchronized Reserve market through a CSP, other revisions described below will allow such customers to participate in RPM through a CSP.

Additionally, PJM proposes to revise section 1.5A.4 (a) of Attachment K-Appendix of the Tariff relating to metering and electronic dispatch signal requirements for Economic Load Response Participants. The revisions state that, with the exception of those load reductions from non-interval metered residential DR customers the CSP has included as part of its demand response portfolio participating in the Pilot Program, the CSP must utilize statistical sampling for such non-interval metered residential DR customers, as set forth in the PJM Manuals. The statistical sampling requirement does not apply to the Pilot Program because the Pilot Program exists in part for the purpose of experimenting with different measurement and verification

processes that could be utilized in the future. Thus, specifying the types of measurement and verification methods that can be used in the Pilot Program would undermine its purpose.²⁰ The specific proposed revisions are as follows:

The Curtailment Service Provider is responsible to ensure for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential Direct Load Control customers not participating in the pilot program under section 1.5A.7, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. .

²¹

Further, section 3.3A.1 of Attachment K-Appendix of the Tariff, which addresses compensation for Economic Load Response Participants, is being revised to state that qualifying demand reductions may now be measured by “non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals.”²² These revisions are necessary to clarify under what circumstances CSPs with demand response portfolios comprised of non-interval metered residential Direct Load Control customers are eligible for compensation.

²⁰ Additionally, PJM is proposing to delete an incorrect reference to the term Load Serving Entity in this section. The reference is incorrect because electric distribution company, which is already listed in this section, is the proper term.

²¹ See OATT ATT K APPX Sec 1.5A.

²² See OATT ATT K APPX Sec 3.3A.

Section 8.3 Attachment K-Appendix of the Tariff, which relates to metering requirements for participants in the Emergency Load Response Program and Pre-Emergency Load Response Program, is being revised to add a new sentence stating that: “Non-interval metered residential customers that have Direct Load Control may use current statistical sampling of interval metering equipment on an electric distribution company account basis in accordance with the PJM Manuals and subject to PJM approval.”²³ This language is necessary because it allows CSPs with such customers to participate in the Emergency Load Response Program and Pre-Emergency Load Response Program. This is important because these are the programs through which CSPs can participate in RPM, and accordingly, these revisions allow CSPs with non-interval metered residential DR customers with statistical sampling to participate in RPM, as they were allowed to under the Pilot Program.²⁴

Section 8.11 Attachment K-Appendix of the Tariff, which addresses Emergency Load Response and Pre-Emergency Load Response Participant Aggregation, is being revised to add new language stating that settlements for such aggregations are to be based on a current statistical sample of end-use customers’ load reductions for non-interval metered residential Direct Load Control customers as set forth in the PJM Manuals.²⁵ PJM is proposing to revise this section for the same reasons it is proposing to revise section 8.3.

Last, section K of Attachment DD-1 of the Tariff is being revised to add new language stating that “[c]urrent load for a statistical sample of end-use customers may be used for

²³ See OATT ATT K APPX Sec 8.3.

²⁴ Similar new language is being added to a subsection 8.3(b) to state that load can be “metered on a representative sample of Electric Distribution Company accounts for non-interval metered residential Direct Load Control in accordance with the PJM Manuals.” See *id.*

²⁵ See OATT ATT K APPX Sec 8.11.

compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval” can be used for the FSL and GLD compliance methods.²⁶ After June 1, 2016, LDLC will no longer be a viable option for measuring compliance. Accordingly, PJM is allowing the FSL and GLD compliance methods to use statistical sampling when measuring compliance for non-interval metered residential DR customers.

c. Transition Provision

PJM is proposing a transition provision for implementing statistical sampling in a new section 5.14E of Attachment DD of the Tariff.²⁷ This transition provision is necessary because some CSPs may already have (or will soon have) cleared Demand Resource commitments for future Delivery Years through RPM Base Residual Auctions (“BRA”) that were eligible for Legacy Direct Load Control, but are unable to implement statistical sampling by June 1, 2016 or may have their estimated load reductions decreased as a result of statistical sampling. Having this transition provision will ensure that CSPs are relieved of their RPM commitments without any financial penalties under appropriate circumstances.

For example, suppose a CSP has a cleared RPM commitment for a future Delivery Year of 10 MW that is partly based on load reductions from non-interval metered residential customers measured using PJM’s current, static methods. However, when measuring the load

²⁶ See OATT ATTACHMENT DD-1.

²⁷ See OATT ATT DD.5.14. The transition provision was originally proposed to be labeled section 5.14D. As further described in section III, the revisions proposed herein were initially approved in January 2015 by PJM’s stakeholders, but an updated transition provision was not approved by PJM’s stakeholders until May 2015. During the stakeholder review process in late 2014, a new section 5.14D of Attachment DD of the Tariff was proposed and is currently pending approval at the Commission. See Proposed Tariff Revisions of PJM Interconnection, L.L.C., Docket No. ER15-623-000 (filed December 12, 2014). Consequently, the pending revisions from that filing were not reviewed by stakeholders when approving this filing in May 2015. Thus, references herein to section 5.14E were reviewed by stakeholders as being references to section 5.14D, although no substantive revisions were made to the transition provision.

reductions from the same residential customers using statistical sampling, the CSP is now only able to deliver 9.5 MW of load reductions based on the more accurate measurements. If the CSP is only able to deliver 9.5 MW when the applicable Delivery Year arrives, it will normally be penalized for the .5 MW shortfall in its performance. Rather than subjecting the CSP to such a penalty, the proposed transition provision will give CSPs the option of being relieved of .5 MW of their RPM commitment without any penalty. If, on the other hand, the CSP is not able to implement statistical sampling at all by June 1, 2016, the CSP will have the option of being relieved of their entire RPM commitment, which in this example would be 10 MW. The proposed transition provision is modeled on a similar transition provision accepted by the Commission that will relieve Capacity Market Sellers of previously cleared RPM commitments for future Delivery Years that were based on Demand Resources unable to comply with PJM's default 30-minute notification requirement for Demand Resources ("DR Operational Transition Provision").²⁸

This proposed new section 5.14E(A) describes the eligibility criteria for the transition provision:

Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the

²⁸ See *PJM Interconnection, L.L.C.*, Proposed Tariff Revisions of PJM Interconnection, L.L.C., Docket No. ER15-135-000 (Oct. 20, 2014); *PJM Interconnection, L.L.C.*, Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER15-135-001 (Jan. 9, 2015).

Base Residual Auction for the 2018/2019 Delivery Year. -A Demand Resource meeting these criteria and the-Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.²⁹

Proposed section 5.14E(B) outlines the information that an Affected Curtailment Service Provider must provide the Office of the Interconnection by the applicable deadline. The information being required is the same as what was required by the Commission when PJM implemented the DR Operational Transition Provision. Section 5.14E(B) also outlines when notice must be given by the Affected Curtailment Service Provider to PJM for Demand Resources unable to comply with statistical sampling during each Applicable Delivery Year.

Section 5.14E(C) relates to information that the Office of the Interconnection must publish related to the amount of “non-viable megawatts” - i.e. the amount of megawatts that are eligible for the transition provision– for each applicable Incremental Auction in every Applicable Delivery Year.³⁰ The publication required by this section provides transparency to the public regarding the amount of non-viable megawatts.

Section 5.14E(D) states that “[p]rior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce . . . the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider .

²⁹ See OATT ATT DD.5.14. Although the BRA for the 2018/2019 Delivery Year has been delayed, and in fact may occur after this filing is accepted by the Commission, PJM is proposing to have the transition provision apply to the 2018/2019 Delivery Year. Had the BRA for the 2018/2019 Delivery Year occurred in May 2015, this transition provision would certainly have been needed because the BRA would have occurred before this filing would have possibly been accepted by the Commission. Given the relative uncertainty of when the BRA for the 2018/2019 Delivery Year will be held, and the new rules that may be relevant to such a BRA, PJM believes it is prudent to allow CSPs to utilize the transition provision regardless of precisely when the BRA occurs relative to the possible acceptance of this filing.

³⁰ See OATT ATT DD.5.14.

. .³¹ This revision allows CSPs to be relieved of their capacity commitments without penalty, as previously described.

Section 5.14D(E) states that for “each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource’s RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.”³² Thus, the consequence for Demand Resources not being able to comply with the statistical sampling method will be for the Affected Curtailment Service Providers to be relieved of their capacity commitments related to such resources. This will mean they will not be penalized; however they also will not receive any corresponding RPM payments associated with the Demand Resources that are unable to comply with statistical sampling.

d. Identification of Load Serving Entity

PJM is proposing revisions to sections 1.5A.3 and 1.5A.10 of Attachment K-Appendix of the Tariff clarifying that CSPs will not be required to identify the relevant Load Serving Entity of their residential customers comprising their demand response portfolios for registration purposes, unless they participate in the Day-ahead Energy Market.³³ CSPs have demand response portfolios based on load reductions from thousands of residential customers, and such customers routinely shift between multiple Load Serving Entities. Tracking which residential customer is assigned to which Load Serving Entity is a complex and costly administrative burden for CSPs

³¹ See *id.*

³² See *id.*

³³ See OATT ATT K APPX Sec 1.5A.

with residential customers. However, because PJM will adjust a Load Serving Entity's day-ahead position based on its amount of load reductions cleared in the Day-ahead Energy Market, the CSP must track residential customers' applicable Load Serving Entity if the CSP participates in the Day-ahead Energy Market so that PJM can accurately clear the Day-ahead Energy Market. However, PJM does not need this information if the CSP participates in the Real-time Energy Market or any Ancillary Services markets, and accordingly will not require the CSP track residential customers' applicable Load Serving Entity unless the CSP participates the Day-ahead Energy Market.

e. Conforming References

Given the addition of sections 5.14E of Attachment DD of the Tariff and the new definition of Legacy Direct Load Control, several sections of the governing documents are being updated with references to these terms where appropriate.³⁴ Several sections of Attachment DD-1 are also being updated to clarify that the Legacy Direct Load Control measurement and verification method will expire on June 1, 2016.³⁵

Further Section 1.5A.6 of Attachment K-Appendix of the Tariff is being revised to state that when determining whether a particular load is variable or non-variable, the customary 60 days' worth of hourly load data provided by the Market Participant (in this case the CSP) shall not be required on an individual customer basis for "non-interval metered" residential

³⁴ See OATT ATT DD.2; OATT ATT DD.5.12; OATT ATT DD.5.14; OATT ATTACHMENT DD-1.

³⁵ See OATT ATTACHMENT DD-1. Further, section J of Attachment DD-1, which addresses customer specific data that is provided by CSPs to PJM in the registration process for the Emergency and Pre-Emergency Load Response Programs, is being revised to remove a reference to "LSE contact information." PJM removed Load Serving Entities from these programs' registration processes in 2013, and neglected to make this conforming revision at the time.

customers.³⁶ This is because the determination will instead be made using the statistical sampling information for non-interval metered residential customers.

f. Other revisions

Section 1.5A.7 of Attachment K-Appendix of the Tariff, which addresses the Pilot Program, is being revised to clarify the circumstances under which a CSP with non-interval metered residential DR customers may participate in the Synchronized Reserve market.³⁷ Further, this section is being revised to clarify that the CSP or PJM (not the customer itself³⁸ or Load Serving Entity) must propose an alternate method for measuring hourly demand reductions, which is consistent with other governing document provisions for commercial and industrial customers. Further, if the Office of the Interconnection approves such alternate measurement, it shall no longer be required to notify all affected Load Serving Entities because PJM may not know the affected Load Serving Entities.

III. STAKEHOLDER REVIEW

On November 20, 2014, the PJM Markets and Reliability Committee endorsed the proposed revisions to the Tariff Operating Agreement and RAA described herein, with the exception of language related to the transition provision's applicability to the 2018/2019 Delivery Year, with a sector weighted vote of 4.03 in favor, 0.97 against.³⁹ At its meeting held January 22, 2015, the PJM Members Committee endorsed and approved those proposed

³⁶ OATT ATT K APPX Sec 1.5A.

³⁷ *See id.*

³⁸ A similar revision is being made to section 8.10 of Attachment K-Appendix of the Tariff. *See* OATT ATT K APPX Sec 8.10.

³⁹ *See* Draft Minutes, PJM Markets and Reliability Committee meeting, November 20, 2014 (available <http://pjm.com/committees-and-groups/committees/mrc.aspx>).

revisions to the Tariff, Operating Agreement and RAA, respectively, by acclamation with one abstention.⁴⁰

After the PJM Members Committee's January 22, 2015 meeting, PJM's staff determined that it would be prudent to delay filing the proposed revisions as a result of the Supreme Court's review of the *EPSA* appeal. Given the delay, PJM's staff determined that the filing would have to be submitted in the spring of 2015, meaning any possible acceptance of the filing would occur after the then scheduled May 2015 BRA for the 2018/2019 Delivery Year. Accordingly, PJM went back to its stakeholders to request that the transition provision be expanded to include the 2018/2019 Delivery Year, but requested no other changes.

On April 23, 2015, the PJM Markets and Reliability Committee endorsed and approved the proposed revisions to the Tariff, Operating Agreement and RAA described herein, including the transition provision's applicability to the 2018/2019 Delivery Year, with one abstention.⁴¹ At its meeting held May 21, 2015, the PJM Members Committee endorsed and approved the proposed revisions to the Tariff, Operating Agreement and RAA, respectively, by acclamation with one abstention.

IV. EFFECTIVE DATE

PJM requests that the Commission issue an order accepting the proposed revisions by no later than August 3, 2015, in accordance with the 60-day notice requirement in section 35.3(a)(1) of the Commission's Regulations 18 C.F.R. Part 35, with an effective date of August 3, 2015.

⁴⁰ See Draft Minutes, PJM Members Committee meeting, January 22, 2015 (available at <http://pjm.com/committees-and-groups/committees/mc.aspx>).

⁴¹ See Draft Minutes, PJM Markets and Reliability Committee meeting, April 23, 2015 (available at <http://pjm.com/committees-and-groups/committees/mrc.aspx>).

V. DOCUMENTS ENCLOSED

Attachment A – redline version of the revised sections to the electronic tariff; and

Attachment B – clean version of the revised sections to the electronic tariff.

VI. CORRESPONDENCE AND COMMUNICATIONS

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VII. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,⁴² PJM will post a copy of this filing to the FERC Filings section of its website, 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 email on the same date this filing is made to all PJM Members and all state utility regulatory commissions in the PJM Region⁴³ 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 also will be available on the

⁴² See 18 C.F.R §§ 35.2(e) and 385.2010(f)(3).

⁴³ PJM already maintains updates and regularly uses e-mail lists for all PJM members and affected state commissions.

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

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Steven Shparber", with a long, sweeping flourish extending to the right.

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Dated: June 4, 2015

Attachment A

Revisions to the
PJM Open Access Transmission Tariff,
PJM Operating Agreement and
PJM Reliability Assurance Agreement

(Marked / Redline Format)

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

Definitions – C-D

1.3BB.03 Cancellation Costs:

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

1.3C Capacity Interconnection Rights:

The rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

1.3D Capacity Resource:

Shall have the meaning provided in the Reliability Assurance Agreement.

1.3E Capacity Transmission Injection Rights:

The rights to schedule energy and capacity deliveries at a Point of Interconnection (as defined in Section 1.33A) of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

1.3F Commencement Date:

The date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

1.4 Commission:

The Federal Energy Regulatory Commission.

1.5 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.5.01 Confidential Information:

Any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

1.5A Consolidated Transmission Owners Agreement:

The certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

1.5B Constructing Entity:

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

1.5C Construction Party:

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

1.5D Construction Service Agreement:

Either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

1.6 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.6A Control Zone:

Shall have the meaning given in the Operating Agreement.

1.6B Controllable A.C. Merchant Transmission Facilities:

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

1.6C Costs:

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

1.6D Counterparty:

PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a market participant or other customer.

1.7 Curtailment:

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

1.7A Customer Facility:

Generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Subparts A of Part IV of the Tariff.

1.7A.01 Customer-Funded Upgrade:

Any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Section 217 of the Tariff, or (ii) is voluntarily undertaken by a market participant in fulfillment of an Upgrade Request pursuant to Section 7.8 of Schedule 1 of the Operating Agreement. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

1.7A.02 Customer Interconnection Facilities:

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

1.7B Daily Capacity Deficiency Rate

Daily Capacity Deficiency Rate is as defined in Schedule 11 of the Reliability Assurance Agreement.

1.7C Deactivation:

The retirement or mothballing of a generating unit governed by Part V of this Tariff.

1.7D Deactivation Avoidable Cost Credit:

The credit paid to Generation Owners pursuant to section 114 of this Tariff.

1.7E Deactivation Avoidable Cost Rate:

The formula rate established pursuant to section 115 of this Tariff.

1.7F Deactivation Date:

The date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

1.7G Default:

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

1.8 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.9A Designated Entity:

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

1.10 Direct Assignment Facilities:

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

1.10.01 Direct Load Control:

Load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

1.5A Economic Load Response Participant.

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

1.5A.1 Qualification.

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

1.5A.2 Special Member.

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

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such

registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

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

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

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

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

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

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

day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

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

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

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

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

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

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

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

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

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

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

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

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible ~~to ensure~~for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range

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

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

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

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

1.5A.5 On-Site Generators.

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

1.5A.6 Variable-Load Customers.

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

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The ~~customer or its~~Curtailment Service Provider or ~~Load Serving Entity~~PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection ("Pilot Period"). ~~In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period.~~ Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the

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

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

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

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

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection’s calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-ahead Scheduling Reserves, until a dispatch

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

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

Economic Load Response Participants shall be compensated under section 3.3A.5 and 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

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

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

iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.5 and 3.3A.6;

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

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

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

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

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

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

1.5A.11 Reporting

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

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 23) by the MWs produced by on-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;
2. Weekend days;
3. Event days. For the purposes of this section an event day shall be either:
 - (i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - (ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.
2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this

section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an

alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\Delta \text{LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and ΔLMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Real-time Energy Market no later than 6:00 p.m. on the day prior to the operating day that submitted a day-ahead offer that cleared or that otherwise are dispatched by the Office of the Interconnection in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may revise the previously specified minimum or maximum load reduction quantity for an operating hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than three hours prior to such operating hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event that the end-use

customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$ and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;
 RTL_{iz} is the real-time load for LSE i in zone z ;
 X is the total export quantity from PJM in that hour; and
 X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJM Settlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established

under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;

v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved

pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

8.3 Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program and Pre-Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. Non-interval metered residential customers that have Direct Load Control may use current statistical sampling of interval metering equipment on an electric distribution company account basis in accordance with the PJM Manuals and subject to PJM approval. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Program and Pre-Emergency Load Response Program participants must meter reductions in demand by using either of the following two methods:

- a) Using metering equipment that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator); or
- b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis, or metered on a representative sample of Electric Distribution Company accounts for non-interval metered residential Direct Load Control in accordance with the PJM Manuals.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

- a) Metering equipment used for retail electric service;
- b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM, in accordance with the requirements herein and in the PJM Manuals; or
- c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

8.10 Non-Hourly Metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The ~~customer or its~~ Curtailment Service Provider must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection (“Pilot Period”). .

Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response and Pre-Emergency Load Response Programs that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response and Pre-Emergency Load Response Participant aggregations shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company ;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. Energy settlement will be based on each individual customer's load reductions, or a current statistical sample of end-use customers' load reductions for non-interval metered residential Direct Load Control customers as set forth in the PJM Manuals, pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions, or a current statistical sample of end-use customers' load reductions, and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and
- v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.
- vi. Certain aggregations of End-Use Customers registered as Full Program Option or Capacity Only Option are subject to the "Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015" in Section 5.14A of Attachment DD of the Tariff.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the *Operating Agreement or RAA*. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1 Annual Demand Resource

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

2.1A Annual Energy Efficiency Resource

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

2.1B Annual Resource

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

2.1C Annual Resource Price Adder

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

2.1D Annual Revenue Rate

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

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

2.2A Base Capacity Demand Resource

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

2.2B Base Capacity Demand Resource Constraint

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

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.2C Base Capacity Demand Resource Price Decrement

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

2.2D Base Capacity Energy Efficiency Resource

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

2.2E Base Capacity Resource

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

2.2F Base Capacity Resource Constraint

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

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

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the

clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.2G Base Capacity Resource Price Decrement

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

2.3 Base Load Generation Resource

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

2.4 Base Offer Segment

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

2.5 Base Residual Auction

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

2.6 Buy Bid

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

2.6A Compliance Aggregation Area (CAA)

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

separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

“Capacity Credit” shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

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

2.9 Capacity Emergency Transfer Objective

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

2.9A Capacity Export Transmission Customer

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

2.9B Capacity Import Limit

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

2.10 Capacity Market Buyer

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

2.11 Capacity Market Seller

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

2.11A Capacity Performance Resource

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

2.11B Capacity Performance Transition Incremental Auction

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

2.12 Capacity Resource

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

2.13 Capacity Resource Clearing Price

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

2.13A Capacity Storage Resource

“Capacity Storage Resource” shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

2.14 Capacity Transfer Right

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

2.14A Conditional Incremental Auction

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

2.15 CONE Area

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

2.16 Cost of New Entry

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

2.16A Credit-Limited Offer

“Credit-Limited Offer” shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

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

2.18 Daily Unforced Capacity Obligation

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

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5, or pursuant to an FRR Capacity Plan.

2.20 Demand Resource

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

2.21 Demand Resource Factor or DR Factor

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

2.22 [Reserved for Future Use]

2.23 EFORD

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

2.23A Emergency Action

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

2.24 Energy Efficiency Resource

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

2.24A Extended Summer Demand Resource

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

2.24B Extended Summer Resource Price Adder

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

2.24C Sub-Annual Resource Reliability Target

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

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

converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

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

2.26 Final RTO Unforced Capacity Obligation

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

2.26A [Reserved]

2.27 First Incremental Auction

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

2.28 Forecast Pool Requirement

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

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

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

2.32 Generator Forced Outage

“Generator Forced Outage” shall have the meaning specified in the Operating Agreement.

2.33 Generator Maintenance Outage

“Generator Maintenance Outage” shall have the meaning specified in the Operating Agreement.

2.33A Generator Planned Outage

“Generator Planned Outage” shall have the meaning specified in the Operating Agreement.

2.34 Incremental Auction

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

“Incremental Capacity Transfer Right” shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Intermittent Resource

“Intermittent Resource” shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

2.36A Limited Demand Resource

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

2.36B Limited Demand Resource Reliability Target

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

2.36C Limited Resource Constraint

“Limited Resource Constraint” shall mean, *for the 2017/2018 Delivery Year*, for the PJM Region

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

2.36D Limited Resource Price Decrement

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

2.37 Load Serving Entity (LSE)

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

2.38 Locational Deliverability Area (LDA)

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

2.39 Locational Deliverability Area Reliability Requirement

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

2.40 Locational Price Adder

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

2.41 Locational Reliability Charge

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

2.41A Locational UCAP

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

2.41B Locational UCAP Seller

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

2.41C Market Seller Offer Cap

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

2.41D Minimum Annual Resource Requirement

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

2.41E Minimum Extended Summer Resource Requirement

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

2.42 Net Cost of New Entry

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

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

2.43A Nominated Energy Efficiency Value

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

2.44 [Reserved]

2.45 Opportunity Cost

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

2.46 Peak-Hour Dispatch

“Peak-Hour Dispatch” shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

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

2.48 Percentage Internal Resources Required

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

2.48A Performance Assessment Hour

“Performance Assessment Hour” shall mean each whole or partial clock-hour for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Hours for a Base Capacity Resource shall not include any hours outside the calendar months of June through September.

2.49 Planned Demand Resource

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

2.50 Planned External Generation Capacity Resource

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

2.50A Planned Generation Capacity Resource

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

2.51 Planning Period

“Planning Period” shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

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

2.53 PJM Region Installed Reserve Margin

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

2.54 PJM Region Peak Load Forecast

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

2.55 PJM Region Reliability Requirement

“PJM Region Reliability Requirement” shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

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

2.57 Qualifying Transmission Upgrade

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

2.58 Reference Resource

“Reference Resource” shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/MWh.

2.59 Reliability Assurance Agreement

“Reliability Assurance Agreement” shall mean that certain “Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region,” on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

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

2.60A Repowered / Repowering

“Repowering” or “Repowered” shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

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

2.61A Scheduled Incremental Auctions

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

2.62 Second Incremental Auction

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

2.63 Sell Offer

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

2.64 [Reserved for Future Use]

2.65 Self-Supply

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

2.65A Short-Term Resource Procurement Target

“Short-Term Resource Procurement Target” shall mean, *for Delivery Years through May 31, 2018*, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

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

2.65B.01 Small Commercial Customer

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

2.65C Sub-Annual Resource Price Decrement

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

2.66 Third Incremental Auction

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

2.67 [Reserved for Future Use]

2.68 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 Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

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

2.69A Updated VRR Curve

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment 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.*

2.69B 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 the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C [and 5.14E](#) of this Attachment DD.

2.69C 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 the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C [and 5.14E](#) of this attachment DD.

2.70 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 Section 5.

2.71 Zonal Capacity Price

“Zonal Capacity Price” shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; for the *2017/2018* Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; *and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;*
- *For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement.*

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of

Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- *For the Delivery years through May 31, 2018, the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;*
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- *For the Delivery Years through May 31, 2018, for each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement*

- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the *2017/2018* Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; *and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;*
- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;
- The Sell Offers submitted in such auction; and
- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(2) of this Attachment, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(1) of this Attachment, and the conditions stated in section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction,* minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, ~~and 5.14C~~ and 5.14E of this Attachment DD. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated

VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by section 5.4(c)(3)(i) of this Attachment, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction*, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by section 5.4(c)(3)(ii) of this Attachment, plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, ~~and 5.14C~~ and 5.14E of this Attachment DD; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction*, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell

back such quantity. *For the Delivery Years through May 31, 2018*, if more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits (“Excess Commitment Credits”) under certain circumstances as follows:

- (A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;
- (B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such

auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

- (C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;
- (D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, *Base Capacity Demand Resource Price Decrements*, and *Base Capacity Resource Price Decrements*, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the

Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).
- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or
- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and
- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-

block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJM Settlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, 5.14B, 5.14C, 5.14D, [5.14E](#) and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJM Settlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) General Rule. Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, *or a* Unit-Specific Exception with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) Applicability. A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including Repowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle technology) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility (as defined in Part 292 of FERC's regulations), where the Capacity Market Seller is the owner of the Qualifying Facility or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) MOPR Floor Offer Price. The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator (“CT”), a combined cycle generator (“CC”), and an integrated gasification combined cycle generator (“IGCC”), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT \$/MW-yr	132,200	130,300	128,900	130,300
CC \$/MW-yr	185,700	176,000	172,600	179,400
IGCC \$/MW-yr	582,042	558,486	547,240	537,306

i) Commencing with the Delivery Year that begins on June 1, 2019, the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above,

except that the heat rate assumed for the combined cycle resource shall be 8.7 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3,198 per MW-year.

(4) **Duration.** The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until (and including) the first Delivery Year for which a Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) **Effect of Exemption or Exception.** To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption or exception and cleared the RPM Auction for which it obtained such exemption or exception shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(10) hereof.

(6) **Self-Supply Exemption.** A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) **Cost and revenue criteria.** The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated Utility and the MOPR Screened Generation Resource is planned

consistent with such LSE’s most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE’s costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE’s business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE’s Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE’s Estimated Capacity Obligation above its Owned and Contracted Capacity (“Net Short”) is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW

Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE's future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long

positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

vi) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vii) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of

the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak. Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) Competitive Entry Exemption. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs of the MOPR Screened Generation Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be “Competitive and Non-Discriminatory” only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller’s decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity

Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance (“O&M”) contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer. The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller’s reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period

identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(9) Exemption/Exception Process.

i) The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.

ii) The Capacity Market Seller must submit its request for a Unit-Specific Exception, Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption or exception that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption or exception criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller

shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

iii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption or exception request. The Office of the Interconnection shall also review all exemption and exception requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption or exception request. The Office of the Interconnection shall reject a requested exemption or exception if the Capacity Market Seller's request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request. If the Office of the Interconnection does not provide its determination on an exemption or exception request by no later than sixty-five (65) days after receipt of the exemption or exception request, the request shall be deemed granted. Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (5) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(10) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared

in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(10) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference

specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This transition provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, “Transition Delivery Years” and each a “Transition Delivery Year”) by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a “Qualified DR Provider.”

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission's order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the

identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this section 5.14A. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this section 5.14A to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

$$\text{DRTC} = (\text{IAP} - \text{BRP}) * \text{DRMW}$$

Where:

DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.
3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this section 5.14A, and
2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that
 - a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,
 - b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year
 - c. an aggregate amount that exceeds:
 - (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus
 - (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,
 - (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this section 5.14A shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this section 5.14A, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and

received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test

procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell

megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource’s RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. *This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.*

B. *For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.*

1. *For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:*

- *the target quantities of Capacity Performance Resources specified below;*
- *the Sell Offers submitted in such auction.*

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. *For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.*

3. *A Capacity Market Seller may offer any Generation Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.*

4. *Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.*

D. *All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.*

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider

because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental

Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a *Base Capacity Demand Resource*, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance

with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

- 1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;
- 2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;
- 3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,
- 4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and
- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand

response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;
- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and
- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights

and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, the product of the Nominated Value of the Demand Resource times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following *four* ways:

| Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).

DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider’s market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider’s market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer’s Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- Supplemental status reports, detailing Demand Resources available, as requested by PJM;
- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer’s contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer’s Peak Load Contribution.

Prior to June 1, 2016, ~~F~~the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, ~~LSE contact information,~~ number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an “unrestricted” peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, ~~F~~for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider’s Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance

reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Prior to June 1, 2016, Compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

$$(PLC) - (Load * LF)$$

Compliance is checked on an individual customer basis for GLD Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance, and will be based on:

- (i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.
- (ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for

each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30 minutes of the clock hour (i.e., “partial dispatch compliance hour”). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer’s Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak *summer and winter* periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2012. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process

intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- *For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;*
- *For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and*

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.*

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. *For Delivery Years through May 31, 2018, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.*

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected

life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

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

Definitions C - D

1.6 Capacity Resource.

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

1.6.01 Catastrophic Force Majeure.

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

1.6A Consolidated Transmission Owners Agreement.

“Consolidated Transmission Owners Agreement” dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

1.7 Control Area.

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

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7.01 Control Zone.

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

1.7.01a Counterparty.

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with Market Participants or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7.02 Default Allocation Assessment.

“Default Allocation Assessment” shall mean the assessment determined pursuant to section 15.2.2 of this Agreement.

1.7.03 Demand Resource.

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

1.7A Designated Entity.

An entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Section 1.5.8 of Schedule 6 of this Agreement.

1.7A.01 Direct Load Control:

Load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

1.7B [Reserved].

1.5A Economic Load Response Participant.

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

1.5A.1 Qualification.

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

1.5A.2 Special Member.

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

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such

registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

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

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

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

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

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type

of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten business days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with section 1.5A hereof, including section 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

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

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

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

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

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

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten business days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority

permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

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

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

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

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

1.5A.4 Metering and Electronic Dispatch Signal.

- a) The Curtailment Service Provider is responsible ~~to ensure for ensuring~~ that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service

Provider, ~~Load Serving Entity~~, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

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

- a. Curtailed Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
 - b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailed Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
 - c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailed Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
 - d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailed Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the matter to the Independent Market Monitor and/or the Federal Energy Regulatory Commission Office of Enforcement.
- b) Curtailed Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent

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

1.5A.6 Variable-Load Customers.

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

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The ~~customer or its~~ Curtailment Service Provider or ~~Load Serving Entity~~ PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection ("Pilot Period"). ~~In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period.~~ Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market ~~or Synchronized Reserve market~~. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.4 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM

Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

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

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

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

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

until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Day-ahead Scheduling Reserves to reduce load.

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

Economic Load Response Participants shall be compensated under section 3.3A.5 and 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

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

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day- Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.5 and 3.3A.6;
- v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the

ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

- vi. Each End-Use Customer site must meet the requirements for market participation by a demand resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and
- vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

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

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

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

1.5A.11 Reporting

- (a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.
- (b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 23) by the MWs produced by On-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads:

- (a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.
 - i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:
 1. NERC holidays;
 2. Weekend days;
 3. Event days. For the purposes of this section an event day shall be either:
 - i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

- ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.
- iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

- i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:
 - 1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
 3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.
- ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.
 - iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

- i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;
- ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\Delta \text{LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and ΔLMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Real-time Energy Market no later than 6:00 p.m. on the day prior to the operating day that submitted a day-ahead offer that cleared or that otherwise are dispatched by the Office of the Interconnection in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may revise the previously specified minimum or maximum load reduction quantity for an operating hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than three hours prior to such operating hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs

associated with a minimum number of contiguous hours for which the demand reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount that the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$
and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;

RTL_{iz} is the real-time load for LSE i in zone z ;

X is the total export quantity from PJM in that hour; and

X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or

equal to the Net Benefits Test shall be compensated by PJMSettlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

- i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;
- ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;
- iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;
- iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;
- v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

- i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- ii. An Economic Load Response Participant's settlements pursuant to 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

- iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.
- iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.
 - i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.
 - ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.
- v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

8.3 Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program and Pre-Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. Non-interval metered residential customers that have Direct Load Control may use current statistical sampling of interval metering equipment on an electric distribution company account basis in accordance with the PJM Manuals and subject to PJM approval. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Program and Pre-Emergency Load Response Program participants must meter reductions in demand by using either of the following two methods:

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

(b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis, or metered on a representative sample of Electric Distribution Company accounts for non-interval metered residential Direct Load Control in accordance with the PJM Manuals.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

(a) Metering equipment used for retail electric service;

(b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM in accordance with the requirements herein and in the PJM Manuals; or

(c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

8.10 Non-Hourly Metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The ~~customer or its~~ Curtailment Service Provider must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection (“Pilot Period”). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response and Pre-Emergency Load Response Programs that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response and Pre-Emergency Load Response Participant aggregations shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company ;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. Energy settlement will be based on each individual customer's load reductions, or a current statistical sample of end-use customers' load reductions for non-interval metered residential Direct Load Control customers as set forth in the PJM Manuals, pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions, or a current statistical sample of end-use customers' load reductions, and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and
- v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.
- vi. Certain aggregations of End-Use Customers registered as Full Program Option or Capacity Only Option are subject to the "Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015" in Section 5.14A of Attachment DD of the Tariff.

Section(s) of the
PJM Reliability Assurance Agreement

(Marked / Redline Format)

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, *a Base Capacity Demand Resource* or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically

incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total

Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the

PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and
- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the

current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and
- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the

threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified

in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

- D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.
- E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.
- F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.
- G. PJM measures Demand Resources in the following *four* ways:
 - | Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on LDLC load

management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider’s market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider’s market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer’s Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

- H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:
- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
 - Supplemental status reports, detailing Demand Resources available, as requested by PJM;
 - Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
 - Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
 - Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.
- I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, ~~t~~The Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

- J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, ~~LSE contact information,~~ number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, ~~F~~for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

- K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Prior to June 1, 2016, cCompliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

$$(PLC) - (Load * LF)$$

Compliance is checked on an individual customer basis for GLD Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance, and will be based on:

- (i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.
- (ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour". The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the

clock hour and as defined in the Manual. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak *summer and winter* periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.
2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project

location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value,

- *For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;*
- *For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.*

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. *For Delivery Years through May 31, 2018, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.*
4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall

not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.
6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.
7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

Attachment B

PJM Open Access Transmission Tariff,
PJM Operating Agreement and
PJM Reliability Assurance Agreement

(Clean Format)

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

Definitions – C-D

1.3BB.03 Cancellation Costs:

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

1.3C Capacity Interconnection Rights:

The rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

1.3D Capacity Resource:

Shall have the meaning provided in the Reliability Assurance Agreement.

1.3E Capacity Transmission Injection Rights:

The rights to schedule energy and capacity deliveries at a Point of Interconnection (as defined in Section 1.33A) of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

1.3F Commencement Date:

The date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

1.4 Commission:

The Federal Energy Regulatory Commission.

1.5 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.5.01 Confidential Information:

Any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

1.5A Consolidated Transmission Owners Agreement:

The certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

1.5B Constructing Entity:

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

1.5C Construction Party:

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

1.5D Construction Service Agreement:

Either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

1.6 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.6A Control Zone:

Shall have the meaning given in the Operating Agreement.

1.6B Controllable A.C. Merchant Transmission Facilities:

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

1.6C Costs:

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

1.6D Counterparty:

PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a market participant or other customer.

1.7 Curtailment:

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

1.7A Customer Facility:

Generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Subparts A of Part IV of the Tariff.

1.7A.01 Customer-Funded Upgrade:

Any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Section 217 of the Tariff, or (ii) is voluntarily undertaken by a market participant in fulfillment of an Upgrade Request pursuant to Section 7.8 of Schedule 1 of the Operating Agreement. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

1.7A.02 Customer Interconnection Facilities:

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

1.7B Daily Capacity Deficiency Rate

Daily Capacity Deficiency Rate is as defined in Schedule 11 of the Reliability Assurance Agreement.

1.7C Deactivation:

The retirement or mothballing of a generating unit governed by Part V of this Tariff.

1.7D Deactivation Avoidable Cost Credit:

The credit paid to Generation Owners pursuant to section 114 of this Tariff.

1.7E Deactivation Avoidable Cost Rate:

The formula rate established pursuant to section 115 of this Tariff.

1.7F Deactivation Date:

The date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

1.7G Default:

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

1.8 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.9A Designated Entity:

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

1.10 Direct Assignment Facilities:

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

1.10.01 Direct Load Control:

Load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

1.5A Economic Load Response Participant.

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

1.5A.1 Qualification.

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

1.5A.2 Special Member.

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

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such

registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

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

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

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

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

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

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

day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

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

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

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

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

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

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

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

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

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

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

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

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the

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

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

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

electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

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

1.5A.6 Variable-Load Customers.

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

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection ("Pilot Period"). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.4 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic

Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

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

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

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

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection’s calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection’s calling of a Synchronized Reserve Event (or such instruction to reduce load)

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

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

Economic Load Response Participants shall be compensated under section 3.3A.5 and 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

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

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.5 and 3.3A.6;
- v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and

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

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

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

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

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

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

1.5A.11 Reporting

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

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by on-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;
2. Weekend days;
3. Event days. For the purposes of this section an event day shall be either:
 - (i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - (ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.
2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this

section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an

alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\Delta \text{LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and ΔLMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Real-time Energy Market no later than 6:00 p.m. on the day prior to the operating day that submitted a day-ahead offer that cleared or that otherwise are dispatched by the Office of the Interconnection in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may revise the previously specified minimum or maximum load reduction quantity for an operating hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than three hours prior to such operating hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event that the end-use

customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$ and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;
 RTL_{iz} is the real-time load for LSE i in zone z ;
 X is the total export quantity from PJM in that hour; and
 X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJM Settlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established

under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

- ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;
- iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;
- iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;
- v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

- i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- ii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.
- iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved

pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

8.3 Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program and Pre-Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. Non-interval metered residential customers that have Direct Load Control may use current statistical sampling of interval metering equipment on an electric distribution company account basis in accordance with the PJM Manuals and subject to PJM approval. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Program and Pre-Emergency Load Response Program participants must meter reductions in demand by using either of the following two methods:

- a) Using metering equipment that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator); or
- b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis, or metered on a representative sample of Electric Distribution Company accounts for non-interval metered residential Direct Load Control in accordance with the PJM Manuals.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

- a) Metering equipment used for retail electric service;
- b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM, in accordance with the requirements herein and in the PJM Manuals; or
- c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

8.10 Non-Hourly Metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The Curtailment Service Provider must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection (“Pilot Period”). .

Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response and Pre-Emergency Load Response Programs that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response and Pre-Emergency Load Response Participant aggregations shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company ;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. Energy settlement will be based on each individual customer's load reductions, or a current statistical sample of end-use customers' load reductions for non-interval metered residential Direct Load Control customers as set forth in the PJM Manuals, pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions, or a current statistical sample of end-use customers' load reductions, and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and
- v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.
- vi. Certain aggregations of End-Use Customers registered as Full Program Option or Capacity Only Option are subject to the "Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015" in Section 5.14A of Attachment DD of the Tariff.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the *Operating Agreement or RAA*. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1 Annual Demand Resource

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

2.1A Annual Energy Efficiency Resource

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

2.1B Annual Resource

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

2.1C Annual Resource Price Adder

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

2.1D Annual Revenue Rate

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

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

2.2A Base Capacity Demand Resource

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

2.2B Base Capacity Demand Resource Constraint

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

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.2C Base Capacity Demand Resource Price Decrement

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

2.2D Base Capacity Energy Efficiency Resource

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

2.2E Base Capacity Resource

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

2.2F Base Capacity Resource Constraint

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

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

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the

clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.2G Base Capacity Resource Price Decrement

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

2.3 Base Load Generation Resource

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

2.4 Base Offer Segment

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

2.5 Base Residual Auction

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

2.6 Buy Bid

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

2.6A Compliance Aggregation Area (CAA)

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

separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

“Capacity Credit” shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

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

2.9 Capacity Emergency Transfer Objective

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

2.9A Capacity Export Transmission Customer

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

2.9B Capacity Import Limit

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

2.10 Capacity Market Buyer

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

2.11 Capacity Market Seller

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

2.11A Capacity Performance Resource

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

2.11B Capacity Performance Transition Incremental Auction

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

2.12 Capacity Resource

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

2.13 Capacity Resource Clearing Price

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

2.13A Capacity Storage Resource

“Capacity Storage Resource” shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

2.14 Capacity Transfer Right

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

2.14A Conditional Incremental Auction

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

2.15 CONE Area

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

2.16 Cost of New Entry

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

2.16A Credit-Limited Offer

“Credit-Limited Offer” shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

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

2.18 Daily Unforced Capacity Obligation

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

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5, or pursuant to an FRR Capacity Plan.

2.20 Demand Resource

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

2.21 Demand Resource Factor or DR Factor

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

2.22 [Reserved for Future Use]

2.23 EFORD

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

2.23A Emergency Action

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

2.24 Energy Efficiency Resource

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

2.24A Extended Summer Demand Resource

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

2.24B Extended Summer Resource Price Adder

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

2.24C Sub-Annual Resource Reliability Target

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

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

converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

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

2.26 Final RTO Unforced Capacity Obligation

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

2.26A [Reserved]

2.27 First Incremental Auction

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

2.28 Forecast Pool Requirement

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

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

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

2.32 Generator Forced Outage

“Generator Forced Outage” shall have the meaning specified in the Operating Agreement.

2.33 Generator Maintenance Outage

“Generator Maintenance Outage” shall have the meaning specified in the Operating Agreement.

2.33A Generator Planned Outage

“Generator Planned Outage” shall have the meaning specified in the Operating Agreement.

2.34 Incremental Auction

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

“Incremental Capacity Transfer Right” shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Intermittent Resource

“Intermittent Resource” shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

2.36A Limited Demand Resource

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

2.36B Limited Demand Resource Reliability Target

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

2.36C Limited Resource Constraint

“Limited Resource Constraint” shall mean, *for the 2017/2018 Delivery Year*, for the PJM Region

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

2.36D Limited Resource Price Decrement

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

2.37 Load Serving Entity (LSE)

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

2.38 Locational Deliverability Area (LDA)

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

2.39 Locational Deliverability Area Reliability Requirement

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

2.40 Locational Price Adder

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

2.41 Locational Reliability Charge

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

2.41A Locational UCAP

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

2.41B Locational UCAP Seller

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

2.41C Market Seller Offer Cap

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

2.41D Minimum Annual Resource Requirement

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

2.41E Minimum Extended Summer Resource Requirement

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

2.42 Net Cost of New Entry

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

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

2.43A Nominated Energy Efficiency Value

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

2.44 [Reserved]

2.45 Opportunity Cost

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

2.46 Peak-Hour Dispatch

“Peak-Hour Dispatch” shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

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

2.48 Percentage Internal Resources Required

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

2.48A Performance Assessment Hour

“Performance Assessment Hour” shall mean each whole or partial clock-hour for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Hours for a Base Capacity Resource shall not include any hours outside the calendar months of June through September.

2.49 Planned Demand Resource

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

2.50 Planned External Generation Capacity Resource

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

2.50A Planned Generation Capacity Resource

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

2.51 Planning Period

“Planning Period” shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

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

2.53 PJM Region Installed Reserve Margin

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

2.54 PJM Region Peak Load Forecast

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

2.55 PJM Region Reliability Requirement

“PJM Region Reliability Requirement” shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

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

2.57 Qualifying Transmission Upgrade

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

2.58 Reference Resource

“Reference Resource” shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/MWh.

2.59 Reliability Assurance Agreement

“Reliability Assurance Agreement” shall mean that certain “Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region,” on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

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

2.60A Repowered / Repowering

“Repowering” or “Repowered” shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

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

2.61A Scheduled Incremental Auctions

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

2.62 Second Incremental Auction

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

2.63 Sell Offer

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

2.64 [Reserved for Future Use]

2.65 Self-Supply

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

2.65A Short-Term Resource Procurement Target

“Short-Term Resource Procurement Target” shall mean, *for Delivery Years through May 31, 2018*, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

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

2.65B.01 Small Commercial Customer

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

2.65C Sub-Annual Resource Price Decrement

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

2.66 Third Incremental Auction

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

2.67 [Reserved for Future Use]

2.68 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 Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

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

2.69A Updated VRR Curve

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment 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.*

2.69B 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 the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C and 5.14E of this Attachment DD.

2.69C 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 the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C and 5.14E of this attachment DD.

2.70 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 Section 5.

2.71 Zonal Capacity Price

“Zonal Capacity Price” shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; for the *2017/2018* Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; *and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;*
- *For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement.*

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of

Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- *For the Delivery years through May 31, 2018, the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;*
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- *For the Delivery Years through May 31, 2018, for each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement*

- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the *2017/2018* Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; *and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;*
- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;
- The Sell Offers submitted in such auction; and
- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(2) of this Attachment, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(1) of this Attachment, and the conditions stated in section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction,* minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, 5.14C and 5.14E of this Attachment DD. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR

Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by section 5.4(c)(3)(i) of this Attachment, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction*, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by section 5.4(c)(3)(ii) of this Attachment, plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, 5.14C and 5.14E of this Attachment DD; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction*, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell

back such quantity. *For the Delivery Years through May 31, 2018*, if more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits (“Excess Commitment Credits”) under certain circumstances as follows:

- (A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;
- (B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such

auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

- (C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;
- (D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, *Base Capacity Demand Resource Price Decrements*, and *Base Capacity Resource Price Decrements*, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the

Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).
- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or
- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and
- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-

block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJM Settlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJM Settlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) General Rule. Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, *or a* Unit-Specific Exception with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) Applicability. A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including Repowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle technology) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility (as defined in Part 292 of FERC's regulations), where the Capacity Market Seller is the owner of the Qualifying Facility or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) MOPR Floor Offer Price. The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator (“CT”), a combined cycle generator (“CC”), and an integrated gasification combined cycle generator (“IGCC”), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT \$/MW-yr	132,200	130,300	128,900	130,300
CC \$/MW-yr	185,700	176,000	172,600	179,400
IGCC \$/MW-yr	582,042	558,486	547,240	537,306

i) Commencing with the Delivery Year that begins on June 1, 2019, the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above,

except that the heat rate assumed for the combined cycle resource shall be 8.7 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3,198 per MW-year.

(4) **Duration.** The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until (and including) the first Delivery Year for which a Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) **Effect of Exemption or Exception.** To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption or exception and cleared the RPM Auction for which it obtained such exemption or exception shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(10) hereof.

(6) **Self-Supply Exemption.** A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) **Cost and revenue criteria.** The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated Utility and the MOPR Screened Generation Resource is planned

consistent with such LSE’s most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE’s costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE’s business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE’s Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE’s Estimated Capacity Obligation above its Owned and Contracted Capacity (“Net Short”) is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW

Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE's future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long

positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

vi) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vii) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of

the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak. Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) Competitive Entry Exemption. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs of the MOPR Screened Generation Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be “Competitive and Non-Discriminatory” only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller’s decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity Market Seller; (B) the Capacity Market Seller has disclosed all material facts

relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance (“O&M”) contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer. The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller’s reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period

identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(9) Exemption/Exception Process.

i) The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.

ii) The Capacity Market Seller must submit its request for a Unit-Specific Exception, Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption or exception that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption or exception criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller

shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

iii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption or exception request. The Office of the Interconnection shall also review all exemption and exception requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption or exception request. The Office of the Interconnection shall reject a requested exemption or exception if the Capacity Market Seller's request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request. If the Office of the Interconnection does not provide its determination on an exemption or exception request by no later than sixty-five (65) days after receipt of the exemption or exception request, the request shall be deemed granted. Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (5) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(10) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared

in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(10) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference

specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This transition provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, “Transition Delivery Years” and each a “Transition Delivery Year”) by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a “Qualified DR Provider.”

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission's order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the

identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this section 5.14A. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this section 5.14A to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

$$\text{DRTC} = (\text{IAP} - \text{BRP}) * \text{DRMW}$$

Where:

DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.
3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this section 5.14A, and
2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that
 - a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,
 - b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year
 - c. an aggregate amount that exceeds:
 - (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus
 - (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,
 - (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this section 5.14A shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this section 5.14A, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and

received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test

procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell

megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource’s RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. *This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.*

B. *For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.*

1. *For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:*

- *the target quantities of Capacity Performance Resources specified below;*
- *the Sell Offers submitted in such auction.*

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. *For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.*

3. *A Capacity Market Seller may offer any Generation Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.*

4. *Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.*

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider

because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental

Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a *Base Capacity Demand Resource*, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance

with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

- 1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;
- 2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;
- 3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,
- 4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and
- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand

response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;
- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and
- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights

and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, the product of the Nominated Value of the Demand Resource times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following *four* ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).

DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider’s market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider’s market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer’s Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- Supplemental status reports, detailing Demand Resources available, as requested by PJM;
- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer’s contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer’s Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an “unrestricted” peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider’s Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews

of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

$$(PLC) - (Load * LF)$$

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

- (i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.
- (ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30

minutes of the clock hour (i.e., “partial dispatch compliance hour”). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer’s Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak *summer and winter* periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2012. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project

development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- *For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;*
- *For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and*

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.*

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. *For Delivery Years through May 31, 2018, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.*

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and

provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

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

Definitions C - D

1.6 Capacity Resource.

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

1.6.01 Catastrophic Force Majeure.

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

1.6A Consolidated Transmission Owners Agreement.

“Consolidated Transmission Owners Agreement” dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

1.7 Control Area.

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

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7.01 Control Zone.

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

1.7.01a Counterparty.

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with Market Participants or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7.02 Default Allocation Assessment.

“Default Allocation Assessment” shall mean the assessment determined pursuant to section 15.2.2 of this Agreement.

1.7.03 Demand Resource.

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

1.7A Designated Entity.

An entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Section 1.5.8 of Schedule 6 of this Agreement.

1.7A.01 Direct Load Control:

Load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

1.7B [Reserved].

1.5A Economic Load Response Participant.

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

1.5A.1 Qualification.

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

1.5A.2 Special Member.

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

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such

registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

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

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

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

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

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type

of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten business days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with section 1.5A hereof, including section 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

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

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

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

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

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

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten business days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority

permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

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

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

1.5A.3.02 Economic Load Response Regulation Only Registrations.

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

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service

Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

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

- a. Curtailement Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
 - b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailement Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
 - c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailement Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
 - d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailement Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the matter to the Independent Market Monitor and/or the Federal Energy Regulatory Commission Office of Enforcement.
- b) Curtailement Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits

applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

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

1.5A.7 Non-Hourly Metered Customer Pilot.

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

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

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

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

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

applicable, associated with an instruction to a resource committed to provide Day-ahead Scheduling Reserves to reduce load.

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

Economic Load Response Participants shall be compensated under section 3.3A.5 and 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

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

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day- Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.5 and 3.3A.6;
- v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

- vi. Each End-Use Customer site must meet the requirements for market participation by a demand resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and
- vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

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

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

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

1.5A.11 Reporting

- (a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.
- (b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by On-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads:

- (a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.
 - i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:
 1. NERC holidays;
 2. Weekend days;
 3. Event days. For the purposes of this section an event day shall be either:
 - i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

- ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.
- iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

- i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:
 - 1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
 3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.
- ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.
 - iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

- i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;
- ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\Delta \text{LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and ΔLMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Real-time Energy Market no later than 6:00 p.m. on the day prior to the operating day that submitted a day-ahead offer that cleared or that otherwise are dispatched by the Office of the Interconnection in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may revise the previously specified minimum or maximum load reduction quantity for an operating hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than three hours prior to such operating hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs

associated with a minimum number of contiguous hours for which the demand reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount that the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$
and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;

RTL_{iz} is the real-time load for LSE i in zone z ;

X is the total export quantity from PJM in that hour; and

X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or

equal to the Net Benefits Test shall be compensated by PJMSettlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

- i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;
- ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;
- iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;
- iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;
- v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

- i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- ii. An Economic Load Response Participant's settlements pursuant to 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

- iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.
- iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.
 - i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.
 - ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.
- v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

8.3 Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program and Pre-Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. Non-interval metered residential customers that have Direct Load Control may use current statistical sampling of interval metering equipment on an electric distribution company account basis in accordance with the PJM Manuals and subject to PJM approval. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Program and Pre-Emergency Load Response Program participants must meter reductions in demand by using either of the following two methods:

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

(b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis, or metered on a representative sample of Electric Distribution Company accounts for non-interval metered residential Direct Load Control in accordance with the PJM Manuals.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

(a) Metering equipment used for retail electric service;

(b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM in accordance with the requirements herein and in the PJM Manuals; or

(c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

8.10 Non-Hourly Metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The Curtailment Service Provider must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection (“Pilot Period”). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response and Pre-Emergency Load Response Programs that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response and Pre-Emergency Load Response Participant aggregations shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company ;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. Energy settlement will be based on each individual customer's load reductions, or a current statistical sample of end-use customers' load reductions for non-interval metered residential Direct Load Control customers as set forth in the PJM Manuals, pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions, or a current statistical sample of end-use customers' load reductions, and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and
- v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.
- vi. Certain aggregations of End-Use Customers registered as Full Program Option or Capacity Only Option are subject to the "Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015" in Section 5.14A of Attachment DD of the Tariff.

Section(s) of the
PJM Reliability Assurance Agreement
(Clean Format)

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a *Base Capacity Demand Resource* or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically

incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total

Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the

PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and
- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the

current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and
- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the

threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified

in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

- D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.
- E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.
- F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.
- G. PJM measures Demand Resources in the following *four* ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on LDLC load

management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider’s market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider’s market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer’s Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

- H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:
- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
 - Supplemental status reports, detailing Demand Resources available, as requested by PJM;
 - Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
 - Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
 - Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.
- I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

- J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

- K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

$$(PLC) - (Load * LF)$$

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

- (i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.
- (ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour". The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the

clock hour and as defined in the Manual. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak *summer and winter* periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.
2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project

location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value,

- *For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;*
- *For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.*

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. *For Delivery Years through May 31, 2018, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.*
4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall

not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.
6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.
7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.