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March 1, 2024

Debbie-Anne A. Reese, Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426-0001

Re: *PJM Interconnection, L.L.C., Docket No. ER24-1387-000*
Revisions to the Schedule Selection Process for Offer Capped Resources in the Day-ahead Energy Market to Accommodate Next Generation Markets Project Enhancements to the Market Clearing Engine

Dear Secretary Reese,

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the Federal Energy Regulatory Commission's ("Commission") Regulations,[2] PJM Interconnection, L.L.C. ("PJM") proposes to revise the PJM Open Access Transmission Tariff ("Tariff"), Attachment K-Appendix, section 6.4 and the parallel provisions of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), Schedule 1, section 6.4,[3] to reform the offer schedule selection process for clearing the Day-ahead Energy Market. This proposal will help to address the performance impact of multi-schedule modeling on PJM's market clearing engine resulting from the

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[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. Part 35.

[3] The Tariff and OA are currently located under PJM's "Intra-PJM Tariffs" eTariff title. *PJM Interconnection, L.L.C. – Intra-PJM Tariffs*, Federal Energy Regulatory Commission, https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731 (last visited Mar. 1, 2024). Capitalized terms not otherwise defined herein shall have the same meaning as set forth in the Tariff, Operating Agreement, and the Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region ("RAA"). For convenience and ease of understanding, in this letter, PJM cites only to the energy market rules in the Operating Agreement and does not include citations to the parallel rules (or proposed rules) in Tariff, Attachment K-Appendix.

anticipated implementation of the Next Generation Markets project (sometimes referred to as "nGEM") and the anticipated addition of enhanced combined cycle, and energy storage resource, and hybrid models in PJM's Next Generation Markets clearing software.

As discussed below, the proposed revisions are designed to accommodate the expanded functionality in market clearing available through the Next Generation Markets model. However, because such expanded functionality is not yet available and the issue to be addressed is not yet present, PJM respectfully requests that the Commission accept the Tariff and Operating Agreement revisions described herein with an indefinite effective date of 12/31/9998. PJM requests that the Commission grant waiver of its notice requirements[4] and rule on the proposed revisions at this time. Given the time and effort required to develop the nGEM software, PJM is proposing these revisions and seeking Commission approval now to allow these revisions to be coded into the initial nGEM software and avoid unnecessary delay and duplication of efforts that would occur if PJM proposed these revisions later in the nGEM development process, or even after it goes live. Accordingly, PJM respectfully requests Commission action on this filing by May 1, 2024, which is 61 days from the date of this filing.[5]

The proposed Tariff and Operating Agreement revisions were endorsed by PJM Members at the December 20, 2023 PJM Markets and Reliability Committee meeting,

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[4] *See* 18 C.F.R. § 35.3(a).

[5] PJM has assigned an effective date of May 1, 2024, to one eTariff record, Tariff, Attachment K-Appendix, section 4 [Reserved] submitted with this filing (in metadata only) in order to effectuate Commission action by this date.

through a sector-weighted vote of 3.607/5.0,[6] and by the PJM Members Committee meeting on the same day through a sector-weighted vote of 3.515/5.0.[7]

I. BACKGROUND

A. PJM's Current Resource Schedule Selection Process in the Day-Ahead Energy Market.

Market Sellers of generation resources are allowed to submit three types of schedules in the Day-ahead and Real-time Energy Markets: a market-based schedule (non-parameter limited); a cost-based schedule (parameter-limited); and a market-based parameter-limited schedule.[8] The latter two types of schedules are used when a resource fails the three-pivotal supplier ("TPS") test[9] or during certain emergency conditions,[10] respectively. To clear the Day-ahead Energy Market, PJM uses a market clearing optimization software designed to commit resources on schedules that result in the "lowest overall system production cost."[11] The schedule that results in the lowest total overall system production costs depends on a combination of many factors, including the level of

[6] *See* Markets and Reliability Committee, *Minutes*, PJM Interconnection, L.L.C. at 1 (Dec. 20, 2023), https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240124/20240124-consent-agenda-a---draft-mrc-minutes---12202023.ashx.

[7] *See* Members' Committee, *Minutes*, PJM Interconnection, L.L.C. at 2 (Dec. 20, 2023), https://www.pjm.com/-/media/committees-groups/committees/mc/2024/20240124/20240124-consent-agenda-a---draft-mc-minutes---12202023.ashx.

[8] *See, e.g.*, Day-Ahead and Real-Time Market Operations, *PJM Manual 11: Energy and Ancillary Services Market Operations*, PJM Interconnection, L.L.C., § 2.3.3.2, (Dec. 14, 2023), https://www.pjm.com/-/media/documents/manuals/m11.ashx.

[9] *See* Operating Agreement, Schedule 1, section 6.4.1(a).

[10] *See* Operating Agreement, Schedule 1, section 6.6(b)(i).

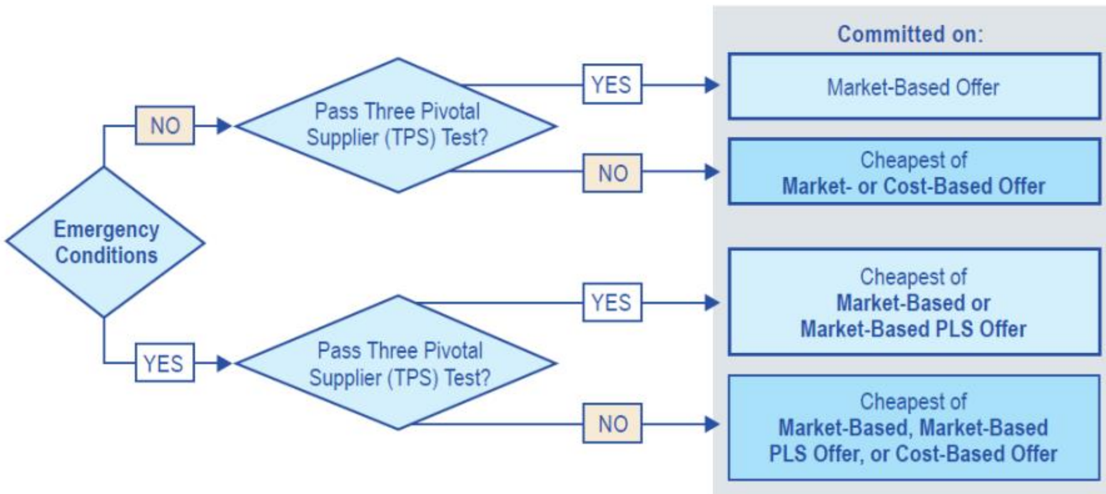
[11] *See* Operating Agreement, Schedule 1, section 6.4.1(a).

output needed from a resource's schedule, the incremental offer up to the needed output level, Start-Up cost, No-load Costs, and other specified operating parameters.

The market clearing engine considers both the offer price and associated operating parameters of all eligible schedules when selecting the schedule on which resources need to be committed. Specifically, in the absence of any emergency conditions and where there is no market power, a market-based resource[12] will have one eligible schedule (market-based schedule). However, if a Market Seller fails the three pivotal supplier test, the resource would have two eligible schedule types (market-based schedule and cost-based schedule). Further, under certain emergency conditions: (1) if the Market Seller has not failed the three pivotal supplier test, the resource will have two eligible schedules (market-based schedule and market-based parameter limited schedule); and (2) if a Market Seller fails the three pivotal supplier test, a resource will have all three types of schedules eligible (market-based schedules, market-based parameter limited schedules, and cost-based schedules) for commitment and dispatch purposes. The figure below shows what schedules are considered by the market clearing optimization software under various conditions.

[12] As used here, a market-based resource refers to a resource that has an eligible market-based schedule. Resources that do not make available a market-based schedule and only submits cost-based offers are referred to as cost-based resources.

Figure 1: PJM's Energy Market Offer Selection Process



The current day-ahead clearing optimization software models each eligible schedule for commitment and dispatch purpose as "logical resource,"[13] with its economic and operating parameters, to determine the cheapest schedule if needed to commit the market resource. As a result, under the current software and depending on system conditions, the market clearing engine may model a single resource as three different logical resources to determine the one that yields, in conjunction with the other committed resources, the lowest overall system production cost.

B. PJM's Resource Schedule Selection Process in the Real-time Energy Market.

In the Real-time Energy Market, the same rules apply with respect to the consideration of offer schedules as in the Day-ahead Energy Market. However, resources

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[13] A logical resource in this context is a modeling representation of a specific operating mode on which a physical supply resource is able to operate such as multiple fuels and/or schedules represented by respective economic and operating parameters, different configuration of combined cycle resource, or different modes of operation of energy storage resource.

are selected and dispatched on the schedule not with the lowest system overall production cost but with the lowest dispatch cost.[14] The difference being that PJM's determination of the lowest overall system production cost is made as part of developing a market-wide solution, whereas the least dispatch cost determination looks at the cost of the subject resource.

For resources committed in the Real-time Energy Market, the resource is committed on the offer with the "lowest total dispatch cost" at the time of commitment.[15] The Total Dispatch cost is determined using the sum of a resource's hourly dispatch cost up to its economic minimum over a resource's minimum run time plus Start-Up Costs.[16] This approach for real-time dispatch is longstanding and necessary to accommodate limitations to the clearing engine, given that the Real-time Energy Market must be cleared within a reasonable amount of time so that real-time commitments can reflect current system conditions. The Commission has twice affirmed in recent years this approach for the Real-time Energy Market.[17]

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[14] *See* Operating Agreement, Schedule 1, sections 6.4.1(a).

[15] Operating Agreement, Schedule 1, section 6.4.1(g).

[16] *See* Operating Agreement, Schedule 1, section 6.4.1(g).

[17] *See PJM Interconnection, L.L.C.*, 185 FERC ¶ 61,158, at PP 30-34 (2023); *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,010, at PP 25-27 (2020).

C. The Next Generation Markets Model and Limitations of the Current Day-ahead Offer Selection Approach.

Multi-configuration models will be an important feature under the new Next Generation Markets model.[18] As part of the Next Generation Markets model, PJM will use configuration-based models for combined cycle, energy storage, and hybrid resources.[19] The Next Generation Markets models for combined cycle and Energy Storage Resources will be multi-configuration-based models in order to accommodate the unique characteristics of these resources—a feature that PJM's current software model cannot provide. The configuration-based energy storage resource model will be extended to hybrid resources to accommodate the operating characteristics of future hybrid resources. This modeling will be needed in the market software to best capture the resource parameters and operational characteristics and therefore extract the benefit that these resources can provide in the most economical manner and simultaneously minimizing the cost to load.

However, the multi-configuration model, in concert with the existing multi-schedule framework described above, will affect the ability of the day-ahead market clearing engine to timely provide a solution. That is, the multiple configurations that can be discretely employed by combined cycle, energy storage, and hybrid resources allows

[18] The Next Generation Markets Model, also referred to as nGEM, is a multi-year partnership between PJM, Midcontinent Independent System Operator, Inc. ("MISO"), ISO New England, Inc. ("ISO-NE"), and General Electric ("GE") to develop and implement software products to improve capability and performance.

[19] *Performance Impact of Multi-Schedule Model in Market Clearing Engine With Configuration-Based Models*, PJM Interconnection, L.L.C., at 4 (Jan. 31, 2023), https://www2.pjm.com/-/media/committees-groups/committees/mic/2023/20230330-special/item-03-2---performance-impact-of-multi-schedule-model-in-market-clearing-engine-with-configuration-based-models---options-paper.ashx.

such resources to offer sets of offer schedules for each configuration or operating mode, which, in turn increases the optimization problem size and the time for the algorithm to reach a solution with the lowest overall system production cost. Explained further, under the current rules, the market clearing engine must evaluate each schedule of each configuration as a distinct, logical resource. For example, a single 2x1 combined cycle plant would have at least six configurations[20] and therefore have six logical resources modeled. If each of these six configurations has two eligible schedules (e.g., cost-based and market-based schedules), then the number of logical resources modeled for a single combined-cycle plant would be 12 (6 configurations x 2 eligible schedules = 12 logical resources). That number grows to 18 logical resources during emergency conditions (on cost-based, market-based, and market-based parameter limited schedules). [21]

The cumulative schedules of configurations of all combined cycles, energy storage and hybrid resources in PJM will dramatically increase the number of logical resources for the clearing engine to evaluate in committing resources. This will significantly increase the optimization problem size and as a result optimization solution times, as the optimization solution time "is not linearly proportional . . . [but] is exponentially proportional" to the optimization problem size for the market clearing engine to select the

[20] For instance, a 2x1 combined cycle plant could have the following six configurations: CT1, CT2, CT1 + CT 2, CT1 + steam, CT2 + steam, CT1 + CT2 + steam.

[21] *Problem/Opportunity Statement: Performance Impact of multi-schedule model in Market Clearing Engine (MCE) in nGEM Enhanced Combined Cycle (ECC) and Energy Storage Resource (ESR) models*, PJM Interconnection, L.L.C., at 1-2 (Jan. 11, 2023) ("PJM Problem Statement") (PJM Problem Statement presented to stakeholders at Dec. 20, 2023 meeting).

eligible schedule that results in the lowest overall system production cost.[22] Given that the Day-ahead Energy Market results are generally posted within a two and a half hour window after the close of day-ahead bid submission period,[23] the market clearing engine will not be able to complete the clearing process in this time period – jeopardizing the adoption of future enhanced combined cycle, energy storage resource, and hybrid models that would accommodate various operating characteristics that are not being considered in the current implemented model.

II. JUSTIFICATION FOR, AND DESCRIPTION OF, THE PROPOSED REVISIONS

A. To Accommodate the More Sophisticated Modeling of Certain Resources in the Next Generation Markets Model, the Day-ahead Offer Selection Approach Should Be Updated.

To best allow the market clearing engine for the Day-ahead Energy Market to timely achieve "the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region,"[24] PJM is proposing to revise the approach for selecting the schedule on which resources may be committed in the Day-ahead Energy Market. Specifically, PJM is proposing to adopt the same schedule selection process that is currently used for clearing the Real-time Energy

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[22] PJM Problem Statement at 1-2.

[23] Operating Agreement, Schedule 1, section 1.10.1A specifies that offers must be submitted by 11:00 a.m. on the day prior to the Operating Day, while Operating Agreement, Schedule 1, section 1.10.8(b) requires PJM to post Day-ahead Energy Market results by 1:30 p.m. before each Operating Day.

[24] Operating Agreement, Schedule 1, section 2.6(a).

Market, such that the market clearing engine will only consider the schedule "which results in the lowest dispatch cost."[25]

More particularly, PJM will utilize the existing formula to determine the lowest dispatch cost, and extend this formula to the Day-ahead Energy Market. Thus, PJM proposes to update the Real-time Energy Market's rules defining the determination of lowest dispatch cost in Operating Agreement, Schedule 1, section 6.4.1(g) to also apply to the Day-ahead Energy Market. As a result, resources committed in the Day-ahead Energy Market would be "committed on the offer with the lowest total dispatch cost."[26]

To be clear, PJM is not proposing to change how the market clearing engine will commit resources in the Day-ahead Energy Market. Rather, PJM will still clear the Day-ahead Energy Market that results in the lowest overall system production cost by using the "day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region."[27] The scope of the changes proposed in this filing is limited to the selection of a schedule that results in the lowest total dispatch cost from eligible schedules for a resource. That selected schedule is then entered into the market clearing engine, which will commit a set of resources that results in the lowest overall system production cost.

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[25] *See* proposed Operating Agreement, Schedule 1, section 6.4.1(a).

[26] Proposed Operating Agreement, Schedule 1, section 6.4.1(g).

[27] Operating Agreement, Schedule 1, section 2.6(a).

Recognizing that PJM does not propose to implement this change until the Next Generation Markets model is used to clear PJM's energy markets, the practical effect of this change when it does become effective would be to remove the selection of the least-cost offer schedule for resources from the market clearing engine and allow PJM to select the least-cost offer based on the lowest total dispatch cost. Selecting the least-cost offer based on the lowest total dispatch cost outside the clearing engine and entering only one schedule per resource into the market clearing engine will allow PJM's day-ahead market clearing engine to timely provide a solution. This will allow for the use of future enhanced combined cycle, energy storage resource, and hybrid models that will accommodate various operating characteristics that are not being considered in the current implemented model. As it relates to Market Participants, the current structure of market-based offers, market-based parameter limited offers, and cost-based offers will be preserved, and there will be no change in how schedules and offer parameters are submitted.

B. The Approach Aligns the Approach for Selecting the Schedule on Which an Offer Capped Resource May Be Committed as Between the Real-Time and Day-ahead Energy Markets.

As noted, the proposed revisions would align the offer selection process between the Real-time and Day-ahead Energy Markets. That is, the offer selection approach PJM is proposing here for the Day-ahead Energy Market is the same approach as is currently used in the Real-time Energy Market. Currently, this approach of determining schedule selection based on a predefined formula has been successfully implemented in PJM's Real-time Market for existing resources and models.[28] PJM has employed the lowest total dispatch cost approach for selecting the schedule on which resource may be committed and dispatched in the Real-time Energy Market since 2008. This approach is just and reasonable and the Commission has twice affirmed the validity of this approach.[29]

III. REQUEST FOR WAIVERS AND PROPOSED EFFECTIVE DATE

As discussed, this change is designed to accommodate the advanced modeling practices that will be available through Next Generation Markets models and thus PJM does not propose to implement this change until that software is in place. Accordingly, PJM requests that the Commission grant waiver of its notice requirements[30] to accept the revisions with an indefinite effective date of 12/31/9998. At least 30 days in advance of implementing nGEM, PJM would submit a filing to notify the Commission of when these revisions will be in effect.

Good cause exists to grant waiver of the notice requirements. The Next Generation Markets is a major technology initiative to replace PJM's existing market clearing platform, and will be the product of a multi-year partnership between PJM, ISO-NE, MISO, and GE—the software developer—to develop a core platform common to each entity that will be customized to each's market rules. As evident from the foregoing discussion of multi-configuration-based models, it will create a substantial improvement in capability

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[28] *See* Operating Agreement, Schedule 1, section 6.4.1(g).

[29] *See PJM Interconnection, L.L.C.*, 185 FERC ¶ 61,158, at PP 30-34; *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,010, at PP 25-27.

[30] *See* 18 C.F.R. § 35.3(a).

and performance. Given the time and effort required to develop the nGEM software, and would be required to adapt-in the enclosed revisions after the fact, PJM is proposing these revisions and seeking Commission approval now to allow these revisions to be coded into the initial nGEM software and avoid unnecessary duplication that would occur if PJM proposed these revisions later in the nGEM development process or after it goes live.

IV. DESCRIPTION OF SUBMITTAL

This filing consists of the following:

1. This transmittal letter;
2. Attachment A - Revised sections of the Tariff and Operating Agreement (redlined version); and
3. Attachment B - Revised sections of the Tariff and Operating Agreement (clean version).

V. CORRESPONDENCE

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

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VI. 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,[31] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[32] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

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

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

VII. CONCLUSION

For the reasons discussed herein, PJM respectfully requests the Commission rule on the enclosed revisions by May 1, 2024, 61 days from the date of filing, accept the proposed amendments to the Tariff and Operating Agreement, effective 12/31/9998 and grant waiver of its notice requirements as discussed herein.

Respectfully submitted,

/s/ *Ryan J. Collins*

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March 1, 2024

Attachment A

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

(Identified by Additional Cover Pages)

(Marked/Redline Format)

Sections of the

PJM Open Access Transmission Tariff

(Marked/Redline Format)

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped as specified below. For such generation resources committed in the Day-ahead Energy Market, if the Office of the Interconnection is able to do so, such offer prices shall be capped for the entire commitment period, and such offer prices will be capped at a cost-based offer in accordance with section 6.4.2 and committed at the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with section 6.4.1(g)~~overall system production cost~~. For such generation resources committed in the Real-time Energy Market such offer prices shall be capped at a cost-based offer in accordance with section 6.4.2 and dispatched on the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with 6.4.1(g) until the earlier of: (i) the resource is released from its commitment by the Office of the Interconnection; (ii) the end of the Operating Day; or (iii) the start of the generation resource's next pre-existing commitment.

The offer on which a resource is committed shall initially be determined at the time of the commitment. If any of the resource's Incremental Energy Offer, No-load Cost or Start-Up Cost are updated for any portion of the offer capped hours subsequent to commitment, the Office of the Interconnection will redetermine the level of the offer cap using the updated offer values. The Office of the Interconnection will dispatch the resource on the market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

Resources that are self-scheduled to run in either the Day-ahead Energy Market or in the Real-time Energy Market are subject to the provisions of this section 6.4. The offer on which a resource is dispatched shall be used to determine any Locational Marginal Price affected by the offer price of such resource and as further limited as described in Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A.

In accordance with section 6.4.1(h), a generation resource that is offer capped in the Real-time Energy Market but released from its commitment by the Office of the Interconnection will be subject to the three pivotal supplier test and further offer capping, as applicable, if the resource is committed for a period later in the same Operating Day.

(b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified in Section 6.4.2 of this Schedule. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. Energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.

(c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.

(d) [Reserved for Future Use]

(e) Offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any period in which a generation resource is committed by the Office of the Interconnection for the Operating Day or any period for which the generation resource has been self-scheduled where (1) there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the Market Seller of the generation resource, when combined with the two largest other generation suppliers, is not pivotal ("three pivotal supplier test"). In the event the Office of the Interconnection system is unable to perform the three pivotal supplier test for a Market Seller, generation resources of that Market Seller that are dispatched to control transmission constraints will be dispatched on the resource's market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

(f) For the purposes of conducting the three pivotal supplier test in subsection (e), the following applies:

(i) All megawatts of available incremental supply, including available self-scheduled supply for which the power distribution factor ("dfax") has an absolute value equal to or greater than the dfax used by the Office of the Interconnection's system operators when evaluating the impact of generation with respect to the constraint ("effective megawatts") will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax ("effective costs"). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.

(ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.

(iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test with respect to any hour in the relevant period will have their units that are dispatched with respect to the constraint offer capped. A generation supplier for the purposes of this section includes corporate affiliates. Supply controlled by a generation supplier or its affiliates by contract with unaffiliated third parties or otherwise will be included as supply of that generation supplier; supply owned by a generation supplier but controlled by an unaffiliated third party by contract or otherwise will be included as supply of that third party.

A generation supplier's units, including self-scheduled units, are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal.

(iv) In the Day-ahead Energy Market, the Office of the Interconnection shall include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

(g) In the Real-time Energy Market and Day-ahead Energy Market, the schedule on which offer capped resources will be placed shall be determined using dispatch cost, where dispatch cost is calculated pursuant to the following formulas:

Dispatch cost for the applicable hour = ((Incremental Energy Offer @ Economic Minimum for the hour [$/MWh] * Economic Minimum for the hour [MW]) + No-load Cost for the hour [$/H])

(i) For resources committed in the Real-time Energy Market at the time of commitment or committed in the Day-ahead Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost~~, at the time of commitment~~ as further detailed in the PJM Manuals,

where:

Total Dispatch cost = Sum of hourly dispatch cost over a resource's minimum run time [$] + Start-Up Cost [$]

(ii) For resources operating in real-time pursuant to a day-ahead or real-time commitment, and whose offers are updated after commitment, the resource is dispatched on the offer with the lowest dispatch cost for the each of the updated hours.

(iii) However, once the resource is dispatched on a cost-based offer, it will remain on a cost-based offer regardless of the determination of the cheapest schedule.

(h) A generation resource that was committed in the Day-ahead Energy Market or Real-time Energy Market, is operating in real time, and may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, will be offer price capped, subject to the outcome of a three pivotal supplier test, for each hour the resource operates beyond its committed hours or Minimum Run Time, whichever is greater, or in the case of resources self-scheduled in the Real-time Energy Market, for each hour the resource operates beyond its first hour of operation, in accordance with the following provisions.

(i) If the resource is operating on a cost-based offer, it will remain on a cost-based offer regardless of the results of the three pivotal supplier test.

(ii) If the resource is operating on a market-based offer and the Market Seller fails the three pivotal supplier test then the resource will be dispatched on the cheaper of its market-based offer or the cost-based offer representing the offer cap as determined by section 6.4.2, whichever results in the lowest dispatch cost as determined under section 6.4.1(g).

(iii) If the Market Seller passes the three pivotal supplier test and the resource is currently operating on a market-based offer then the resource will remain on that offer, unless the Market Seller elects to not have its market-based offer considered for dispatch and to have only the cost-based offer that represents the offer cap level as determined under section 6.4.2 considered for dispatch in which case the resource will be dispatched on its cost-based offer for the remainder of the Operating Day.

(i) If the Office of the Interconnection declares a Market Suspension, in accordance with Operating Agreement, Schedule 1, section 1.11.6 and section 2.5.2, and such Market Suspension is greater than twenty-four (24) consecutive hours, the Office of the Interconnection shall use only cost-based offers for all resources for all market clearing and compensation, regardless of whether a Market Seller fails the three pivotal supplier test.

6.4.2 Level.

(a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;

(ii) For offers of $2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals (“incremental cost”), plus up to the lesser of 10% of such costs or $100 MWh, the sum of which shall not exceed $2,000/MWh; and, for offers greater than $2,000/MWh, the incremental cost of the generation resource;

(iii) For units that are frequently offer capped (“Frequently Mitigated Unit” or “FMU”), and for which the unit’s market-based offer was greater than its cost based offer, the following shall apply:

(a) For units that are offer capped for 60% or more of their run hours, but less than 70% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10% or (ii) incremental cost plus $20 per megawatt-hour;

(b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10%, or (ii) incremental cost plus $30 per megawatt-hour;

(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus $40 per megawatt-hour.

(b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit, pursuant to Section II.A of the Attachment M-Appendix, that it is a "Frequently Mitigated Unit" because it meets all of the following criteria:

(i) The unit was offer capped for the applicable percentage of its run hours, determined on a rolling 12-month basis, effective with a one month lag.

(ii) The unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) are less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.)

(iii) No portion of the unit is included in a FRR Capacity Plan or receiving compensation under Part V of the Tariff.

(iv) The unit is internal to the PJM Region and subject only to PJM dispatch.

(c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an "Associated Unit" upon issuance of written notice from the Market Monitoring Unit pursuant to Section II.A of Attachment M-Appendix, that it meets all of the following criteria:

1. The unit has the identical electric impact on the transmission system as the FMU;

2. The unit (i) belongs to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder;

3. The unit (i) has an average daily cost-based offer, as measured over the preceding 12-month period, that is less than or equal to the FMU's average daily cost-based offer adjusted to include the currently applicable FMU adder or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder.

The offer cap for an associated unit shall be equal to the incremental operating cost of such unit, as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the applicable percentage adder or dollar per megawatt-hour adder as specified in Section 6.4.2(a)(iii)(a), (b), or (c) for the unit with which it is associated.

(d) Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.4.3 Verification of Cost-Based Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based energy offer for a generation resource that includes an Incremental Energy Offer greater than $1,000/megawatt-hour, then, in order for that offer to be eligible to set the applicable Locational Marginal Price as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Operating Agreement Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the Incremental Energy Offer component of such cost-based offer. For each Incremental Energy Offer segment greater than $1,000/megawatt-hour, the Office of the Interconnection shall evaluate whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with the following formula:

Maximum Allowable Incremental Cost ($/MWh segment in accordance with the following formula: @ MW) =
[(Maximum Allowable Operating Rate$_i$) – (Bid Production Cost $_{i-1}$)] / (MW$_i$ – MW$_{i-1}$)

where

i = an offer segment within the Incremental Energy Offer, which is comprised of a pairing of price ($/MWh) and a megawatt quantity

Maximum Allowable Operating Rate (\$/hour @ MW) =
[(Heat Input $_i$ @ MW$_i$) x (Performance Factor) x (Fuel Cost)] x (1 + A)

where

Heat Input = a point on the heat input curve (in MMBtu/hr), determined in accordance with PJM Manual 15, describing the resource's operational characteristics for converting the applicable fuel input (MMBtu) into energy (MWh) specified in the Incremental Energy Offer;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e, design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and

A = Cost adder, in accordance with section 6.4.2(a)(ii) of this Schedule.

Bid Production Cost (\$/hour @ MW) =
$[\sum_{i=1}^{n}(\mathrm{MW_i} - \mathrm{MW_{i-1}})\ \mathrm{x}\ (\mathrm{P_i}) - \frac{1}{2}\ \mathrm{x\ UBS\ x}\ (\mathrm{MW_i} - \mathrm{MW_{i-1}})\ \mathrm{x}\ (\mathrm{P_i} - \mathrm{P_{i-1}})]$ + No-Load Cost

where

MW = the MW quantity per offer segment within the Incremental Energy Offer;

P = the price (in dollars per megawatt-hour) per offer segment within the Incremental Energy Offer;

UBS = Uses Bid-Slope = 0 for block-offer resources (i.e., a resource with an Incremental Energy Offer that uses a step function curve); and 1 for all other resources (i.e., resources with an Incremental Energy Offer that uses a sloped offer curve); and

If the price submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost then that offer segment shall be deemed verified and is eligible to set the applicable Locational Marginal Price. If the price submitted for the offer segment is greater than the Maximum Allowable Incremental Cost, then the Market Seller's cost-based offer for that segment and all segments at an equal or greater price are deemed not verified and are not eligible to set the applicable Locational Marginal Price and such offer shall be price capped at the greater of \$1,000/megawatt-hour or the offer price of the most expensive verified segment on the Incremental Energy Offer for the purpose of setting Locational Marginal Prices; provided however, such Market Seller shall be allowed to submit a challenge to a non-verification determination, including supporting documentation, to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals. Upon review of such documentation, the Office of the Interconnection may determine that the Market Seller's cost-based offer is verified and eligible to set the applicable Locational Marginal Price as described above.

(i) For the first incremental segment (i=1), when the MW in the segment is greater than zero, the first segment shall be screened as a block-loaded segment (UBS=0) as if there was a preceding MW_{i-1} of zero. The Maximum Allowable Incremental Cost calculation for the first incremental would use a preceding Bid Production Cost $_{i-1}$ (at zero MW) equal to the energy No-Load Cost.

(ii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and is the only bid-in segment to be verified, then the segment shall be deemed not verified and subject to the rules as described above.

(iii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and there are additional segments to be verified, then the first segment shall be deemed verified only if the second segment is deemed verified. If the second segment is deemed not verified, then the first segment shall also be deemed not verified and subject to the rules as described above.

(b) If an Economic Load Response Participant a cost-based demand reduction offer that includes incremental costs greater than or equal to \$1,000/megawatt-hour, in order for that offer to be eligible to determine the applicable Locational Marginal Price as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate the incremental costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than \$1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs; and

(ii) The end use customer's incremental costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection, and may not include shutdown costs.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

6.4.3A Verification of Fast-Start Resource Composite Energy Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based offer for a generation resource that is a Fast-Start Resource that results in a Composite Energy Offer that is greater than $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the offer components:

Incremental Energy Offer and No-load Cost components of each offer segment shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the test described in Tariff, Attachment K-Appendix, section 6.4.3.

Start-Up Cost component shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the following formula:

Start-Up Cost ($) = [[(Performance Factor) x (Start Fuel) x (Fuel Cost)] + Start Maintenance Adder + Station Service Cost] x (1 +A)

Where:

Start Fuel =

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e., design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy under Operating Agreement, Schedule 2 and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Start Maintenance Adder = an adder based on all available maintenance expense history for the defined Maintenance Period regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. Only Maintenance Adders specified as $/Start, $/MMBtu, or $/equivalent operating hour can be included in the Start Maintenance Adder;

Station Service Cost = station service usage (MWh) during start-up multiplied by the 12-month rolling average off-peak energy prices as updated quarterly by the Office of the Interconnection.

A = cost adder, in accordance with Tariff, Attachment K-Appendix, section 6.4.2(a)(ii).

(b) Should the submitted Incremental Energy Offer and No-load Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above for any segment, then for the determination of Locational Marginal Prices as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices):

(i) the Incremental Energy Offer for each segment shall be capped at the lesser of the cap described above in Tariff, Attachment K-Appendix, section 6.4.3 or the submitted Incremental Energy Offer; and

(ii) the amortized No-load cost shall be adjusted as described in Tariff, Attachment K-Appendix, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Tariff, Attachment K-Appendix, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(c) Should the submitted Start-Up Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above, then for the determination of Locational Marginal Prices as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the Start-Up Costs shall be adjusted as described in Tariff, Attachment K-Appendix, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Tariff, Attachment K-Appendix, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(d) If an Economic Load Response Participant submits an offer to reduce demand for a Fast-Start Resource where the maximum segment of the resulting Composite Energy Offer exceeds $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate such costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs and shutdown costs; and

(ii) The end use customer's incremental and shutdown costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental and shutdown costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

Should the submitted shutdown cost exceed the reasonably supported costs for that resource, then for the determination of Locational Marginal Prices as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the shutdown costs shall be adjusted as described in Tariff, Attachment K-Appendix, section 2.4 (Determination of Energy Offers Used in

Calculating Real-time Prices) and Tariff, Attachment K-Appendix, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

Sections of the

PJM Operating Agreement

(Marked/Redline Format)

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped as specified below. For such generation resources committed in the Day-ahead Energy Market, if the Office of the Interconnection is able to do so, such offer prices shall be capped for the entire commitment period, and such offer prices will be capped at a cost-based offer in accordance with section 6.4.2 and committed at the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with section 6.4.1(g)~~overall system production cost~~. For such generation resources committed in the Real-time Energy Market such offer prices shall be capped at a cost-based offer in accordance with section 6.4.2 and dispatched on the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with 6.4.1(g) until the earlier of: (i) the resource is released from its commitment by the Office of the Interconnection; (ii) the end of the Operating Day; or (iii) the start of the generation resource's next pre-existing commitment.

The offer on which a resource is committed shall initially be determined at the time of the commitment. If any of the resource's Incremental Energy Offer, No-load Cost or Start-Up Cost are updated for any portion of the offer capped hours subsequent to commitment, the Office of the Interconnection will redetermine the level of the offer cap using the updated offer values. The Office of the Interconnection will dispatch the resource on the market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

Resources that are self-scheduled to run in either the Day-ahead Energy Market or in the Real-time Energy Market are subject to the provisions of this section 6.4. The offer on which a resource is dispatched shall be used to determine any Locational Marginal Price affected by the offer price of such resource and as further limited as described in Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A.

In accordance with section 6.4.1(h), a generation resource that is offer capped in the Real-time Energy Market but released from its commitment by the Office of the Interconnection will be subject to the three pivotal supplier test and further offer capping, as applicable, if the resource is committed for a period later in the same Operating Day.

(b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified in Section 6.4.2 of this Schedule. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. Energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.

(c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.

(d) [Reserved for Future Use]

(e) Offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any period in which a generation resource is committed by the Office of the Interconnection for the Operating Day or any period for which the generation resource has been self-scheduled where (1) there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the Market Seller of the generation resource, when combined with the two largest other generation suppliers, is not pivotal ("three pivotal supplier test"). In the event the Office of the Interconnection system is unable to perform the three pivotal supplier test for a Market Seller, generation resources of that Market Seller that are dispatched to control transmission constraints will be dispatched on the resource's market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

(f) For the purposes of conducting the three pivotal supplier test in subsection (e), the following applies:

(i) All megawatts of available incremental supply, including available self-scheduled supply for which the power distribution factor ("dfax") has an absolute value equal to or greater than the dfax used by the Office of the Interconnection's system operators when evaluating the impact of generation with respect to the constraint ("effective megawatts") will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax ("effective costs"). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.

(ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.

(iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test with respect to any hour in the relevant period will have their units that are dispatched with respect to the constraint offer capped. A generation supplier for the purposes of this section includes corporate affiliates. Supply controlled by a generation supplier or its affiliates by contract with unaffiliated third parties or otherwise will be included as supply of that generation supplier; supply owned by a generation supplier but controlled by an unaffiliated third party by contract or otherwise will be included as supply of that third party.

A generation supplier's units, including self-scheduled units, are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal.

(iv) In the Day-ahead Energy Market, the Office of the Interconnection shall include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

(g) In the Real-time Energy Market and Day-ahead Energy Market, the schedule on which offer capped resources will be placed shall be determined using dispatch cost, where dispatch cost is calculated pursuant to the following formulas:

Dispatch cost for the applicable hour = ((Incremental Energy Offer @ Economic Minimum for the hour [$/MWh] * Economic Minimum for the hour [MW]) + No-load Cost for the hour [$/H])

(i) For resources committed in the Real-time Energy Market at the time of commitment or committed in the Day-ahead Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost at~~, the time of commitment~~ as further detailed in the PJM Manuals,

where:

Total Dispatch cost = Sum of hourly dispatch cost over a resource's minimum run time [$] + Start-Up Cost [$]

(ii) For resources operating in real-time pursuant to a day-ahead or real-time commitment, and whose offers are updated after commitment, the resource is dispatched on the offer with the lowest dispatch cost for the each of the updated hours.

(iii) However, once the resource is dispatched on a cost-based offer, it will remain on a cost-based offer regardless of the determination of the cheapest schedule.

(h) A generation resource that was committed in the Day-ahead Energy Market or Real-time Energy Market, is operating in real time, and may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, will be offer price capped, subject to the outcome of a three pivotal supplier test, for each hour the resource operates beyond its committed hours or Minimum Run Time, whichever is greater, or in the case of resources self-scheduled in the Real-time Energy Market, for each hour the resource operates beyond its first hour of operation, in accordance with the following provisions.

(i) If the resource is operating on a cost-based offer, it will remain on a cost-based offer regardless of the results of the three pivotal supplier test.

(ii) If the resource is operating on a market-based offer and the Market Seller fails the three pivotal supplier test then the resource will be dispatched on the cheaper of its market-based offer or the cost-based offer representing the offer cap as determined by section 6.4.2, whichever results in the lowest dispatch cost as determined under section 6.4.1(g).

(iii) If the Market Seller passes the three pivotal supplier test and the resource is currently operating on a market-based offer then the resource will remain on that offer, unless the Market Seller elects to not have its market-based offer considered for dispatch and to have only the cost-based offer that represents the offer cap level as determined under section 6.4.2 considered for dispatch in which case the resource will be dispatched on its cost-based offer for the remainder of the Operating Day.

(i) If the Office of the Interconnection declares a Market Suspension, in accordance with Operating Agreement, Schedule 1, section 1.11.6 and section 2.5.2, and such Market Suspension is greater than twenty-four (24) consecutive hours, the Office of the Interconnection shall use only cost-based offers for all resources for all market clearing and compensation, regardless of whether a Market Seller fails the three pivotal supplier test.

6.4.2 Level.

(a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;

(ii) For offers of $2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals (“incremental cost”), plus up to the lesser of 10% of such costs or $100 MWh, the sum of which shall not exceed $2,000/MWh; and, for offers greater than $2,000/MWh, the incremental cost of the generation resource;

(iii) For units that are frequently offer capped (“Frequently Mitigated Unit” or “FMU”), and for which the unit’s market-based offer was greater than its cost based offer, the following shall apply:

(a) For units that are offer capped for 60% or more of their run hours, but less than 70% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10% or (ii) incremental cost plus $20 per megawatt-hour;

(b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10%, or (ii) incremental cost plus $30 per megawatt-hour;

(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus $40 per megawatt-hour.

(b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit, pursuant to Section II.A of the Attachment M-Appendix, that it is a "Frequently Mitigated Unit" because it meets all of the following criteria:

(i) The unit was offer capped for the applicable percentage of its run hours, determined on a rolling 12-month basis, effective with a one month lag.

(ii) The unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) are less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.)

(iii) No portion of the unit is included in a FRR Capacity Plan or receiving compensation under Part V of the Tariff.

(iv) The unit is internal to the PJM Region and subject only to PJM dispatch.

(c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an "Associated Unit" upon issuance of written notice from the Market Monitoring Unit pursuant to Section II.A of Attachment M-Appendix, that it meets all of the following criteria:

1. The unit has the identical electric impact on the transmission system as the FMU;

2. The unit (i) belongs to the same design class (where a design class

includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder;

3. The unit (i) has an average daily cost-based offer, as measured over the preceding 12-month period, that is less than or equal to the FMU's average daily cost-based offer adjusted to include the currently applicable FMU adder or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder.

The offer cap for an associated unit shall be equal to the incremental operating cost of such unit, as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the applicable percentage adder or dollar per megawatt-hour adder as specified in Section 6.4.2(a)(iii)(a), (b), or (c) for the unit with which it is associated.

(d) Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.4.3 Verification of Cost-Based Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based energy offer for a generation resource that includes an Incremental Energy Offer greater than $1,000/megawatt-hour, then, in order for that offer to be eligible to set the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the Incremental Energy Offer component of such cost-based offer. For each Incremental Energy Offer segment greater than $1,000/megawatt-hour, the Office of the Interconnection shall evaluate whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with the following formula:

Maximum Allowable Incremental Cost ($/MWh segment in accordance with the following formula: @ MW) =
[(Maximum Allowable Operating Rate$_i$) – (Bid Production Cost $_{i-1}$)] / (MW$_i$ – MW$_{i-1}$)

where

i = an offer segment within the Incremental Energy Offer, which is comprised of a pairing of price ($/MWh) and a megawatt quantity

Maximum Allowable Operating Rate ($/hour @ MW) =
[(Heat Input $_i$ @ MW_i) x (Performance Factor) x (Fuel Cost)] x (1 + A)

where

Heat Input = a point on the heat input curve (in MMBtu/hr), determined in accordance with PJM Manual 15, describing the resource's operational characteristics for converting the applicable fuel input (MMBtu) into energy (MWh) specified in the Incremental Energy Offer;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e, design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and

A = Cost adder, in accordance with section 6.4.2(a)(ii) of this Schedule.

Bid Production Cost ($/hour @ MW) =
$[\sum_{i=1}^{n}(MW_i - MW_{i-1})\ x\ (P_i) - \frac{1}{2}\ x\ UBS\ x\ (MW_i - MW_{i-1})\ x\ (P_i - P_{i-1})]$ + No-Load Cost

where

MW = the MW quantity per offer segment within the Incremental Energy Offer;

P = the price (in dollars per megawatt-hour) per offer segment within the Incremental Energy Offer;

UBS = Uses Bid-Slope = 0 for block-offer resources (i.e., a resource with an Incremental Energy Offer that uses a step function curve); and 1 for all other resources (i.e., resources with an Incremental Energy Offer that uses a sloped offer curve); and

If the price submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost then that offer segment shall be deemed verified and is eligible to set the applicable Locational Marginal Price. If the price submitted for the offer segment is greater than the Maximum Allowable Incremental Cost, then the Market Seller's cost-based offer for that segment and all segments at an equal or greater price are deemed not verified and are not eligible to set the applicable Locational Marginal Price and such offer shall be price capped at the greater of $1,000/megawatt-hour or the offer price of the most expensive verified segment on the

Incremental Energy Offer for the purpose of setting Locational Marginal Prices; provided however, such Market Seller shall be allowed to submit a challenge to a non-verification determination, including supporting documentation, to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals. Upon review of such documentation, the Office of the Interconnection may determine that the Market Seller's cost-based offer is verified and eligible to set the applicable Locational Marginal Price as described above.

(i) For the first incremental segment (i=1), when the MW in the segment is greater than zero, the first segment shall be screened as a block-loaded segment (UBS=0) as if there was a preceding MW_{i-1} of zero. The Maximum Allowable Incremental Cost calculation for the first incremental would use a preceding Bid Production Cost $_{i-1}$ (at zero MW) equal to the energy No-Load Cost.

(ii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and is the only bid-in segment to be verified, then the segment shall be deemed not verified and subject to the rules as described above.

(iii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and there are additional segments to be verified, then the first segment shall be deemed verified only if the second segment is deemed verified. If the second segment is deemed not verified, then the first segment shall also be deemed not verified and subject to the rules as described above.

(b) If an Economic Load Response Participant a cost-based demand reduction offer that includes incremental costs greater than or equal to $1,000/megawatt-hour, in order for that offer to be eligible to determine the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate the incremental costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs; and

(ii) The end use customer's incremental costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection, and may not include shutdown costs.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

6.4.3A Verification of Fast-Start Resource Composite Energy Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based offer for a generation resource that is a Fast-Start Resource that results in a Composite Energy Offer that is greater than $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the offer components:

Incremental Energy Offer and No-load Cost components of each offer segment shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the test described in Operating Agreement, Schedule 1, section 6.4.3.

Start-Up Cost component shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the following formula:

Start-Up Cost ($) = [[(Performance Factor) x (Start Fuel) x (Fuel Cost)] + Start Maintenance Adder + Station Service Cost] x (1 +A)

Where:

Start Fuel =

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e., design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy under Operating Agreement, Schedule 2 and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Start Maintenance Adder = an adder based on all available maintenance expense history for the defined Maintenance Period regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. Only Maintenance Adders specified as $/Start, $/MMBtu, or $/equivalent operating hour can be included in the Start Maintenance Adder;

Station Service Cost = station service usage (MWh) during start-up multiplied by the 12-month rolling average off-peak energy prices as updated quarterly by the Office of the Interconnection.

A = cost adder, in accordance with Operating Agreement, Schedule 1, section 6.4.2(a)(ii).

(b) Should the submitted Incremental Energy Offer and No-load Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above for any segment, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices):

(i) the Incremental Energy Offer for each segment shall be capped at the lesser of the cap described above in Operating Agreement, Schedule 1, section 6.4.3 or the submitted Incremental Energy Offer; and

(ii) the amortized No-load cost shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in

Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(c) Should the submitted Start-Up Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Start-Up Costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(d) If an Economic Load Response Participant submits an offer to reduce demand for a Fast-Start Resource where the maximum segment of the resulting Composite Energy Offer exceeds $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate such costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs and shutdown costs; and

(ii) The end use customer's incremental and shutdown costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental and shutdown costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

Should the submitted shutdown cost exceed the reasonably supported costs for that resource, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the shutdown costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

Attachment B

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

(Identified by Additional Cover Pages)

(Clean Format)

Sections of the

PJM Open Access Transmission Tariff

(Clean Format)

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped as specified below. For such generation resources committed in the Day-ahead Energy Market, if the Office of the Interconnection is able to do so, such offer prices shall be capped for the entire commitment period, and such offer prices will be capped at a cost-based offer in accordance with section 6.4.2 and committed at the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with section 6.4.1(g). For such generation resources committed in the Real-time Energy Market such offer prices shall be capped at a cost-based offer in accordance with section 6.4.2 and dispatched on the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with 6.4.1(g) until the earlier of: (i) the resource is released from its commitment by the Office of the Interconnection; (ii) the end of the Operating Day; or (iii) the start of the generation resource's next pre-existing commitment.

The offer on which a resource is committed shall initially be determined at the time of the commitment. If any of the resource's Incremental Energy Offer, No-load Cost or Start-Up Cost are updated for any portion of the offer capped hours subsequent to commitment, the Office of the Interconnection will redetermine the level of the offer cap using the updated offer values. The Office of the Interconnection will dispatch the resource on the market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

Resources that are self-scheduled to run in either the Day-ahead Energy Market or in the Real-time Energy Market are subject to the provisions of this section 6.4. The offer on which a resource is dispatched shall be used to determine any Locational Marginal Price affected by the offer price of such resource and as further limited as described in Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A.

In accordance with section 6.4.1(h), a generation resource that is offer capped in the Real-time Energy Market but released from its commitment by the Office of the Interconnection will be subject to the three pivotal supplier test and further offer capping, as applicable, if the resource is committed for a period later in the same Operating Day.

(b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified in Section 6.4.2 of this Schedule. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. Energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.

(c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.

(d) [Reserved for Future Use]

(e) Offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any period in which a generation resource is committed by the Office of the Interconnection for the Operating Day or any period for which the generation resource has been self-scheduled where (1) there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the Market Seller of the generation resource, when combined with the two largest other generation suppliers, is not pivotal ("three pivotal supplier test"). In the event the Office of the Interconnection system is unable to perform the three pivotal supplier test for a Market Seller, generation resources of that Market Seller that are dispatched to control transmission constraints will be dispatched on the resource's market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

(f) For the purposes of conducting the three pivotal supplier test in subsection (e), the following applies:

(i) All megawatts of available incremental supply, including available self-scheduled supply for which the power distribution factor ("dfax") has an absolute value equal to or greater than the dfax used by the Office of the Interconnection's system operators when evaluating the impact of generation with respect to the constraint ("effective megawatts") will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax ("effective costs"). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.

(ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.

(iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test with respect to any hour in the relevant period will have their units that are dispatched with respect to the constraint offer capped. A generation supplier for the purposes of this section includes corporate affiliates. Supply controlled by a generation supplier or its affiliates by contract with unaffiliated third parties or otherwise will be included as supply of that generation supplier; supply owned by a generation supplier but controlled by an unaffiliated third party by contract or otherwise will be included as supply of that third party.

A generation supplier's units, including self-scheduled units, are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal.

(iv) In the Day-ahead Energy Market, the Office of the Interconnection shall include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

(g) In the Real-time Energy Market and Day-ahead Energy Market, the schedule on which offer capped resources will be placed shall be determined using dispatch cost, where dispatch cost is calculated pursuant to the following formulas:

Dispatch cost for the applicable hour = ((Incremental Energy Offer @ Economic Minimum for the hour [$/MWh] * Economic Minimum for the hour [MW]) + No-load Cost for the hour [$/H])

(i) For resources committed in the Real-time Energy Market at the time of commitment or committed in the Day-ahead Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost, as further detailed in the PJM Manuals,

where:

Total Dispatch cost = Sum of hourly dispatch cost over a resource's minimum run time [$] + Start-Up Cost [$]

(ii) For resources operating in real-time pursuant to a day-ahead or real-time commitment, and whose offers are updated after commitment, the resource is dispatched on the offer with the lowest dispatch cost for the each of the updated hours.

(iii) However, once the resource is dispatched on a cost-based offer, it will remain on a cost-based offer regardless of the determination of the cheapest schedule.

(h) A generation resource that was committed in the Day-ahead Energy Market or Real-time Energy Market, is operating in real time, and may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, will be offer price capped, subject to the outcome of a three pivotal supplier test, for each hour the resource operates beyond its committed hours or Minimum Run Time, whichever is greater, or in the case of resources self-scheduled in the Real-time Energy Market, for each hour the resource operates beyond its first hour of operation, in accordance with the following provisions.

(i) If the resource is operating on a cost-based offer, it will remain on a cost-based offer regardless of the results of the three pivotal supplier test.

(ii) If the resource is operating on a market-based offer and the Market Seller fails the three pivotal supplier test then the resource will be dispatched on the cheaper of its market-based offer or the cost-based offer representing the offer cap as determined by section 6.4.2, whichever results in the lowest dispatch cost as determined under section 6.4.1(g).

(iii) If the Market Seller passes the three pivotal supplier test and the resource is currently operating on a market-based offer then the resource will remain on that offer, unless the Market Seller elects to not have its market-based offer considered for dispatch and to have only the cost-based offer that represents the offer cap level as determined under section 6.4.2 considered for dispatch in which case the resource will be dispatched on its cost-based offer for the remainder of the Operating Day.

(i) If the Office of the Interconnection declares a Market Suspension, in accordance with Operating Agreement, Schedule 1, section 1.11.6 and section 2.5.2, and such Market Suspension is greater than twenty-four (24) consecutive hours, the Office of the Interconnection shall use only cost-based offers for all resources for all market clearing and compensation, regardless of whether a Market Seller fails the three pivotal supplier test.

6.4.2 Level.

(a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;

(ii) For offers of $2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals (“incremental cost”), plus up to the lesser of 10% of such costs or $100 MWh, the sum of which shall not exceed $2,000/MWh; and, for offers greater than $2,000/MWh, the incremental cost of the generation resource;

(iii) For units that are frequently offer capped (“Frequently Mitigated Unit” or “FMU”), and for which the unit’s market-based offer was greater than its cost based offer, the following shall apply:

(a) For units that are offer capped for 60% or more of their run hours, but less than 70% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10% or (ii) incremental cost plus $20 per megawatt-hour;

(b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10%, or (ii) incremental cost plus $30 per megawatt-hour;

(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus $40 per megawatt-hour.

(b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit, pursuant to Section II.A of the Attachment M-Appendix, that it is a "Frequently Mitigated Unit" because it meets all of the following criteria:

(i) The unit was offer capped for the applicable percentage of its run hours, determined on a rolling 12-month basis, effective with a one month lag.

(ii) The unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) are less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.)

(iii) No portion of the unit is included in a FRR Capacity Plan or receiving compensation under Part V of the Tariff.

(iv) The unit is internal to the PJM Region and subject only to PJM dispatch.

(c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an "Associated Unit" upon issuance of written notice from the Market Monitoring Unit pursuant to Section II.A of Attachment M-Appendix, that it meets all of the following criteria:

1. The unit has the identical electric impact on the transmission system as the FMU;

2. The unit (i) belongs to the same design class (where a design class

includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder;

3. The unit (i) has an average daily cost-based offer, as measured over the preceding 12-month period, that is less than or equal to the FMU's average daily cost-based offer adjusted to include the currently applicable FMU adder or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder.

The offer cap for an associated unit shall be equal to the incremental operating cost of such unit, as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the applicable percentage adder or dollar per megawatt-hour adder as specified in Section 6.4.2(a)(iii)(a), (b), or (c) for the unit with which it is associated.

(d) Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.4.3 Verification of Cost-Based Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based energy offer for a generation resource that includes an Incremental Energy Offer greater than $1,000/megawatt-hour, then, in order for that offer to be eligible to set the applicable Locational Marginal Price as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Operating Agreement Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the Incremental Energy Offer component of such cost-based offer. For each Incremental Energy Offer segment greater than $1,000/megawatt-hour, the Office of the Interconnection shall evaluate whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with the following formula:

Maximum Allowable Incremental Cost ($/MWh segment in accordance with the following formula: @ MW) =
$[\ (\text{Maximum Allowable Operating Rate}_i) - (\text{Bid Production Cost}_{i-1})\ ] / (MW_i - MW_{i-1})$

where

i = an offer segment within the Incremental Energy Offer, which is comprised of a pairing of price ($/MWh) and a megawatt quantity

Maximum Allowable Operating Rate ($/hour @ MW) =
[(Heat Input $_i$ @ MW_i) x (Performance Factor) x (Fuel Cost)] x (1 + A)

where

Heat Input = a point on the heat input curve (in MMBtu/hr), determined in accordance with PJM Manual 15, describing the resource's operational characteristics for converting the applicable fuel input (MMBtu) into energy (MWh) specified in the Incremental Energy Offer;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e, design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and

A = Cost adder, in accordance with section 6.4.2(a)(ii) of this Schedule.

Bid Production Cost ($/hour @ MW) =
$[\sum_{i=1}^{n}(MW_i - MW_{i-1}) \text{ x } (P_i) - \frac{1}{2} \text{ x UBS x } (MW_i - MW_{i-1}) \text{ x } (P_i - P_{i-1})]$ + No-Load Cost

where

MW = the MW quantity per offer segment within the Incremental Energy Offer;

P = the price (in dollars per megawatt-hour) per offer segment within the Incremental Energy Offer;

UBS = Uses Bid-Slope = 0 for block-offer resources (i.e., a resource with an Incremental Energy Offer that uses a step function curve); and 1 for all other resources (i.e., resources with an Incremental Energy Offer that uses a sloped offer curve); and

If the price submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost then that offer segment shall be deemed verified and is eligible to set the applicable Locational Marginal Price. If the price submitted for the offer segment is greater than the Maximum Allowable Incremental Cost, then the Market Seller's cost-based offer for that segment and all segments at an equal or greater price are deemed not verified and are not eligible to set the applicable Locational Marginal Price and such offer shall be price capped at the greater of $1,000/megawatt-hour or the offer price of the most expensive verified segment on the

Incremental Energy Offer for the purpose of setting Locational Marginal Prices; provided however, such Market Seller shall be allowed to submit a challenge to a non-verification determination, including supporting documentation, to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals. Upon review of such documentation, the Office of the Interconnection may determine that the Market Seller's cost-based offer is verified and eligible to set the applicable Locational Marginal Price as described above.

(i) For the first incremental segment (i=1), when the MW in the segment is greater than zero, the first segment shall be screened as a block-loaded segment (UBS=0) as if there was a preceding MW_{i-1} of zero. The Maximum Allowable Incremental Cost calculation for the first incremental would use a preceding Bid Production Cost $_{i-1}$ (at zero MW) equal to the energy No-Load Cost.

(ii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and is the only bid-in segment to be verified, then the segment shall be deemed not verified and subject to the rules as described above.

(iii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and there are additional segments to be verified, then the first segment shall be deemed verified only if the second segment is deemed verified. If the second segment is deemed not verified, then the first segment shall also be deemed not verified and subject to the rules as described above.

(b) If an Economic Load Response Participant a cost-based demand reduction offer that includes incremental costs greater than or equal to $1,000/megawatt-hour, in order for that offer to be eligible to determine the applicable Locational Marginal Price as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate the incremental costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs; and

(ii) The end use customer's incremental costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection, and may not include shutdown costs.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

6.4.3A Verification of Fast-Start Resource Composite Energy Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based offer for a generation resource that is a Fast-Start Resource that results in a Composite Energy Offer that is greater than $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the offer components:

Incremental Energy Offer and No-load Cost components of each offer segment shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the test described in Tariff, Attachment K-Appendix, section 6.4.3.

Start-Up Cost component shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the following formula:

Start-Up Cost ($) = [[(Performance Factor) x (Start Fuel) x (Fuel Cost)] + Start Maintenance Adder + Station Service Cost] x (1 +A)

Where:

Start Fuel =

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e., design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy under Operating Agreement, Schedule 2 and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Start Maintenance Adder = an adder based on all available maintenance expense history for the defined Maintenance Period regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. Only Maintenance Adders specified as $/Start, $/MMBtu, or $/equivalent operating hour can be included in the Start Maintenance Adder;

Station Service Cost = station service usage (MWh) during start-up multiplied by the 12-month rolling average off-peak energy prices as updated quarterly by the Office of the Interconnection.

A = cost adder, in accordance with Tariff, Attachment K-Appendix, section 6.4.2(a)(ii).

(b) Should the submitted Incremental Energy Offer and No-load Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above for any segment, then for the determination of Locational Marginal Prices as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices):

(i) the Incremental Energy Offer for each segment shall be capped at the lesser of the cap described above in Tariff, Attachment K-Appendix, section 6.4.3 or the submitted Incremental Energy Offer; and

(ii) the amortized No-load cost shall be adjusted as described in Tariff, Attachment K-Appendix, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Tariff, Attachment K-Appendix, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(c) Should the submitted Start-Up Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above, then for the determination of Locational Marginal Prices as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the Start-Up Costs shall be adjusted as described in Tariff, Attachment K-Appendix, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Tariff, Attachment K-Appendix, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(d) If an Economic Load Response Participant submits an offer to reduce demand for a Fast-Start Resource where the maximum segment of the resulting Composite Energy Offer exceeds $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate such costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs and shutdown costs; and

(ii) The end use customer's incremental and shutdown costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental and shutdown costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

Should the submitted shutdown cost exceed the reasonably supported costs for that resource, then for the determination of Locational Marginal Prices as described in Tariff, Attachment K-Appendix, section 2.5 (for determining Real-time Prices) and Tariff, Attachment K-Appendix, section 2.6 (for determining Day-ahead Prices), the shutdown costs shall be adjusted as described in Tariff, Attachment K-Appendix, section 2.4 (Determination of Energy Offers Used in

Calculating Real-time Prices) and Tariff, Attachment K-Appendix, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

Sections of the

PJM Operating Agreement

(Clean Format)

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped as specified below. For such generation resources committed in the Day-ahead Energy Market, if the Office of the Interconnection is able to do so, such offer prices shall be capped for the entire commitment period, and such offer prices will be capped at a cost-based offer in accordance with section 6.4.2 and committed at the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with section 6.4.1(g). For such generation resources committed in the Real-time Energy Market such offer prices shall be capped at a cost-based offer in accordance with section 6.4.2 and dispatched on the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with 6.4.1(g) until the earlier of: (i) the resource is released from its commitment by the Office of the Interconnection; (ii) the end of the Operating Day; or (iii) the start of the generation resource's next pre-existing commitment.

The offer on which a resource is committed shall initially be determined at the time of the commitment. If any of the resource's Incremental Energy Offer, No-load Cost or Start-Up Cost are updated for any portion of the offer capped hours subsequent to commitment, the Office of the Interconnection will redetermine the level of the offer cap using the updated offer values. The Office of the Interconnection will dispatch the resource on the market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

Resources that are self-scheduled to run in either the Day-ahead Energy Market or in the Real-time Energy Market are subject to the provisions of this section 6.4. The offer on which a resource is dispatched shall be used to determine any Locational Marginal Price affected by the offer price of such resource and as further limited as described in Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A.

In accordance with section 6.4.1(h), a generation resource that is offer capped in the Real-time Energy Market but released from its commitment by the Office of the Interconnection will be subject to the three pivotal supplier test and further offer capping, as applicable, if the resource is committed for a period later in the same Operating Day.

(b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified in Section 6.4.2 of this Schedule. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. Energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.

(c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.

(d) [Reserved for Future Use]

(e) Offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any period in which a generation resource is committed by the Office of the Interconnection for the Operating Day or any period for which the generation resource has been self-scheduled where (1) there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the Market Seller of the generation resource, when combined with the two largest other generation suppliers, is not pivotal ("three pivotal supplier test"). In the event the Office of the Interconnection system is unable to perform the three pivotal supplier test for a Market Seller, generation resources of that Market Seller that are dispatched to control transmission constraints will be dispatched on the resource's market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

(f) For the purposes of conducting the three pivotal supplier test in subsection (e), the following applies:

(i) All megawatts of available incremental supply, including available self-scheduled supply for which the power distribution factor ("dfax") has an absolute value equal to or greater than the dfax used by the Office of the Interconnection's system operators when evaluating the impact of generation with respect to the constraint ("effective megawatts") will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax ("effective costs"). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.

(ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.

(iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test with respect to any hour in the relevant period will have their units that are dispatched with respect to the constraint offer capped. A generation supplier for the purposes of this section includes corporate affiliates. Supply controlled by a generation supplier or its affiliates by contract with unaffiliated third parties or otherwise will be included as supply of that generation supplier; supply owned by a generation supplier but controlled by an unaffiliated third party by contract or otherwise will be included as supply of that third party.

A generation supplier's units, including self-scheduled units, are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal.

(iv) In the Day-ahead Energy Market, the Office of the Interconnection shall include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

(g) In the Real-time Energy Market and Day-ahead Energy Market, the schedule on which offer capped resources will be placed shall be determined using dispatch cost, where dispatch cost is calculated pursuant to the following formulas:

Dispatch cost for the applicable hour = ((Incremental Energy Offer @ Economic Minimum for the hour [$/MWh] * Economic Minimum for the hour [MW]) + No-load Cost for the hour [$/H])

(i) For resources committed in the Real-time Energy Market at the time of commitment or committed in the Day-ahead Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost at, as further detailed in the PJM Manuals,

where:

Total Dispatch cost = Sum of hourly dispatch cost over a resource's minimum run time [$] + Start-Up Cost [$]

(ii) For resources operating in real-time pursuant to a day-ahead or real-time commitment, and whose offers are updated after commitment, the resource is dispatched on the offer with the lowest dispatch cost for the each of the updated hours.

(iii) However, once the resource is dispatched on a cost-based offer, it will remain on a cost-based offer regardless of the determination of the cheapest schedule.

(h) A generation resource that was committed in the Day-ahead Energy Market or Real-time Energy Market, is operating in real time, and may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, will be offer price capped, subject to the outcome of a three pivotal supplier test, for each hour the resource operates beyond its committed hours or Minimum Run Time, whichever is greater, or in the case of resources self-scheduled in the Real-time Energy Market, for each hour the resource operates beyond its first hour of operation, in accordance with the following provisions.

(i) If the resource is operating on a cost-based offer, it will remain on a cost-based offer regardless of the results of the three pivotal supplier test.

(ii) If the resource is operating on a market-based offer and the Market Seller fails the three pivotal supplier test then the resource will be dispatched on the cheaper of its market-based offer or the cost-based offer representing the offer cap as determined by section 6.4.2, whichever results in the lowest dispatch cost as determined under section 6.4.1(g).

(iii) If the Market Seller passes the three pivotal supplier test and the resource is currently operating on a market-based offer then the resource will remain on that offer, unless the Market Seller elects to not have its market-based offer considered for dispatch and to have only the cost-based offer that represents the offer cap level as determined under section 6.4.2 considered for dispatch in which case the resource will be dispatched on its cost-based offer for the remainder of the Operating Day.

(i) If the Office of the Interconnection declares a Market Suspension, in accordance with Operating Agreement, Schedule 1, section 1.11.6 and section 2.5.2, and such Market Suspension is greater than twenty-four (24) consecutive hours, the Office of the Interconnection shall use only cost-based offers for all resources for all market clearing and compensation, regardless of whether a Market Seller fails the three pivotal supplier test.

6.4.2 Level.

(a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;

(ii) For offers of $2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals (“incremental cost”), plus up to the lesser of 10% of such costs or $100 MWh, the sum of which shall not exceed $2,000/MWh; and, for offers greater than $2,000/MWh, the incremental cost of the generation resource;

(iii) For units that are frequently offer capped (“Frequently Mitigated Unit” or “FMU”), and for which the unit’s market-based offer was greater than its cost based offer, the following shall apply:

(a) For units that are offer capped for 60% or more of their run hours, but less than 70% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10% or (ii) incremental cost plus $20 per megawatt-hour;

(b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10%, or (ii) incremental cost plus $30 per megawatt-hour;

(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus $40 per megawatt-hour.

(b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit, pursuant to Section II.A of the Attachment M-Appendix, that it is a "Frequently Mitigated Unit" because it meets all of the following criteria:

(i) The unit was offer capped for the applicable percentage of its run hours, determined on a rolling 12-month basis, effective with a one month lag.

(ii) The unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) are less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.)

(iii) No portion of the unit is included in a FRR Capacity Plan or receiving compensation under Part V of the Tariff.

(iv) The unit is internal to the PJM Region and subject only to PJM dispatch.

(c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an "Associated Unit" upon issuance of written notice from the Market Monitoring Unit pursuant to Section II.A of Attachment M-Appendix, that it meets all of the following criteria:

1. The unit has the identical electric impact on the transmission system as the FMU;

2. The unit (i) belongs to the same design class (where a design class includes generation that is the same size and utilizes the same technology,

without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder;

3. The unit (i) has an average daily cost-based offer, as measured over the preceding 12-month period, that is less than or equal to the FMU's average daily cost-based offer adjusted to include the currently applicable FMU adder or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder.

The offer cap for an associated unit shall be equal to the incremental operating cost of such unit, as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the applicable percentage adder or dollar per megawatt-hour adder as specified in Section 6.4.2(a)(iii)(a), (b), or (c) for the unit with which it is associated.

(d) Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.4.3 Verification of Cost-Based Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based energy offer for a generation resource that includes an Incremental Energy Offer greater than $1,000/megawatt-hour, then, in order for that offer to be eligible to set the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the Incremental Energy Offer component of such cost-based offer. For each Incremental Energy Offer segment greater than $1,000/megawatt-hour, the Office of the Interconnection shall evaluate whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with the following formula:

Maximum Allowable Incremental Cost ($/MWh segment in accordance with the following formula: @ MW) =
[(Maximum Allowable Operating Rate$_i$) – (Bid Production Cost $_{i-1}$)] / (MW$_i$ – MW$_{i-1}$)

where

i = an offer segment within the Incremental Energy Offer, which is comprised of a pairing of price ($/MWh) and a megawatt quantity

Maximum Allowable Operating Rate ($/hour @ MW) =

$$[(\text{Heat Input}_i @ MW_i) \times (\text{Performance Factor}) \times (\text{Fuel Cost})] \times (1 + A)$$

where

Heat Input = a point on the heat input curve (in MMBtu/hr), determined in accordance with PJM Manual 15, describing the resource's operational characteristics for converting the applicable fuel input (MMBtu) into energy (MWh) specified in the Incremental Energy Offer;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e, design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and

A = Cost adder, in accordance with section 6.4.2(a)(ii) of this Schedule.

Bid Production Cost ($/hour @ MW) =
$[\sum_{i=1}^{n}(MW_i - MW_{i-1}) \times (P_i) - \frac{1}{2} \times UBS \times (MW_i - MW_{i-1}) \times (P_i - P_{i-1})]$ + No-Load Cost

where

MW = the MW quantity per offer segment within the Incremental Energy Offer;

P = the price (in dollars per megawatt-hour) per offer segment within the Incremental Energy Offer;

UBS = Uses Bid-Slope = 0 for block-offer resources (i.e., a resource with an Incremental Energy Offer that uses a step function curve); and 1 for all other resources (i.e., resources with an Incremental Energy Offer that uses a sloped offer curve); and

If the price submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost then that offer segment shall be deemed verified and is eligible to set the applicable Locational Marginal Price. If the price submitted for the offer segment is greater than the Maximum Allowable Incremental Cost, then the Market Seller's cost-based offer for that segment and all segments at an equal or greater price are deemed not verified and are not eligible to set the applicable Locational Marginal Price and such offer shall be price capped at the greater of $1,000/megawatt-hour or the offer price of the most expensive verified segment on the Incremental Energy Offer for the purpose of setting Locational Marginal Prices; provided however, such Market Seller shall be allowed to submit a challenge to a non-verification determination, including supporting documentation, to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals. Upon review of such documentation, the Office of the Interconnection may determine that the Market Seller's cost-based offer is verified and eligible to set the applicable Locational Marginal Price as described above.

(i) For the first incremental segment (i=1), when the MW in the segment is greater than zero, the first segment shall be screened as a block-loaded segment (UBS=0) as if there was a preceding MW_{i-1} of zero. The Maximum Allowable Incremental Cost calculation for the first incremental would use a preceding Bid Production Cost $_{i-1}$ (at zero MW) equal to the energy No-Load Cost.

(ii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and is the only bid-in segment to be verified, then the segment shall be deemed not verified and subject to the rules as described above.

(iii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and there are additional segments to be verified, then the first segment shall be deemed verified only if the second segment is deemed verified. If the second segment is deemed not verified, then the first segment shall also be deemed not verified and subject to the rules as described above.

(b) If an Economic Load Response Participant a cost-based demand reduction offer that includes incremental costs greater than or equal to $1,000/megawatt-hour, in order for that offer to be eligible to determine the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate the incremental costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs; and

(ii) The end use customer's incremental costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection, and may not include shutdown costs.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

6.4.3A Verification of Fast-Start Resource Composite Energy Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based offer for a generation resource that is a Fast-Start Resource that results in a Composite Energy Offer that is greater than $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the offer components:

Incremental Energy Offer and No-load Cost components of each offer segment shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the test described in Operating Agreement, Schedule 1, section 6.4.3.

Start-Up Cost component shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the following formula:

Start-Up Cost ($) = [[(Performance Factor) x (Start Fuel) x (Fuel Cost)] + Start Maintenance Adder + Station Service Cost] x (1 +A)

Where:

Start Fuel =

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e., design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy under Operating Agreement, Schedule 2 and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Start Maintenance Adder = an adder based on all available maintenance expense history for the defined Maintenance Period regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. Only Maintenance Adders specified as $/Start, $/MMBtu, or $/equivalent operating hour can be included in the Start Maintenance Adder;

Station Service Cost = station service usage (MWh) during start-up multiplied by the 12-month rolling average off-peak energy prices as updated quarterly by the Office of the Interconnection.

A = cost adder, in accordance with Operating Agreement, Schedule 1, section 6.4.2(a)(ii).

(b) Should the submitted Incremental Energy Offer and No-load Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above for any segment, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices):

(i) the Incremental Energy Offer for each segment shall be capped at the lesser of the cap described above in Operating Agreement, Schedule 1, section 6.4.3 or the submitted Incremental Energy Offer; and

(ii) the amortized No-load cost shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in

Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(c) Should the submitted Start-Up Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Start-Up Costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(d) If an Economic Load Response Participant submits an offer to reduce demand for a Fast-Start Resource where the maximum segment of the resulting Composite Energy Offer exceeds $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate such costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs and shutdown costs; and

(ii) The end use customer's incremental and shutdown costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental and shutdown costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

Should the submitted shutdown cost exceed the reasonably supported costs for that resource, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the shutdown costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).