

December 24, 2014

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

Re: *PJM Interconnection, L.L.C.*, Docket No. ER15-____-000

Dear Ms. Bose:

PJM Interconnection, L.L.C. (“PJM”), pursuant to section 205 of the Federal Power Act (“FPA”), 16 U.S.C. § 824d, and section 35.13 of the Commission’s regulations, 18 C.F.R. § 35.13, hereby submits a proposed revision to Attachment DD, section 5.14 of PJM’s Open Access Transmission Tariff (“Tariff”) to permit it to enter into, and recover the costs of, capacity agreements secured outside the Reliability Pricing Model (“RPM”) Auctions¹ for the specific purpose of alleviating resource adequacy concerns during the 2015/2016 Delivery Year.² All such agreements will be subject to case-by-case review and approval by the Commission under FPA section 205. This Tariff change establishes the standards and considerations PJM suggests for review of such agreements, given their narrow and time-limited focus, and the Tariff mechanism for recovery of the costs of Commission-approved agreements. In support of this filing, PJM includes the affidavit of Mr. Michael J. Kormos (“Kormos Aff.”), PJM’s Executive Vice President—Operations.

PJM proposes an effective date of February 23, 2015 for these changes, i.e., 61 days after the date of this filing.

¹ Capitalized terms not defined herein have the meaning set forth in the PJM Open Access Transmission Tariff (“Tariff”), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”) or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (“RAA”).

² In RPM, a Delivery Year is a twelve-month period beginning on June 1 of a calendar year and ending on May 31 of the following calendar year. See Tariff, Attachment DD, section 2.19.

I. INTRODUCTION AND SUMMARY

PJM emphasizes at the outset that it has secured capacity commitments for the 2015/2016 Delivery Year in excess of the 15.6% Installed Reserve Margin (“IRM”) approved for that Delivery Year. But recent developments have raised concerns about those resource commitments.

First, a key portion of that capacity consists of Demand Resources, which were committed in accordance with PJM’s approved Tariff and long-standing Commission policy, and which have performed well in prior Delivery Years (within the limits on Demand Resource availability established by PJM’s approved Tariff). This filing is not prompted by concern for the past performance of Demand Resources. Rather, PJM is concerned that the recent federal appellate decision in *EPSA*³ and the pending *FirstEnergy Complaint*⁴ raise a risk that is difficult to quantify, but nonetheless foreseeable, that PJM might be unable to compensate those committed Demand Resources, or treat them as Capacity Resources, during the 2015 summer peak season. The possibility for the *EPSA* court’s mandate to issue this spring, with ensuing developments at the Commission both on the *FirstEnergy Complaint* and on remand from *EPSA*, could at a minimum create considerable uncertainty in the market on the status of those Demand Resources, and their ultimate ability to obtain compensation, and in the worst case could effectively nullify that compensation and the associated commitments during all or part of the summer when those resources are most needed. As shown in the Mr. Kormos’s affidavit, if those Demand Resource commitments—presently estimated at over 11,000 megawatts—were effectively nullified before the start of the next Delivery Year, PJM would enter the summer of 2015 with capacity significantly below the level dictated by its approved IRM. What is worse, that shortfall would come in a year when the PJM Region faces the greatest megawatt quantity of generation retirements, by far, of any single year in PJM’s history. Consequently, there simply is not much uncommitted capacity remaining available to fill such a shortfall, were it to occur.

PJM stresses that it is *not*, through this filing, calling upon the Commission to rule upon the application of *EPSA* to capacity or to predict if, or when, the *EPSA* mandate might issue. PJM has argued (in the context of the *FirstEnergy Complaint* proceeding) that the Demand Resource commitments for the 2015 summer peak can and should remain in place, and nothing in this filing should be read as changing in any way PJM’s firm view on the validity of those pre-existing resource commitments. But PJM cannot

³ *Elec. Power Supply Ass’n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014) (“*EPSA*”).

⁴ See Emergency Complaint and Request for Fast Track Processing of FirstEnergy Service Company, Docket No. EL14-55-000, at 1-2 (May 23, 2014) (“*Initial FirstEnergy Complaint*”); Amended Complaint of FirstEnergy Service Company, Docket No. EL14-55-000, at 1-5 (Sept. 22, 2014) (“*Amended FirstEnergy Complaint*”) (collectively, the “*FirstEnergy Complaint*”).

control the outcome of further developments regarding *EPSA*, any possible *EPSA* mandate, or any possible *EPSA* remand, or regarding the Commission's actions on the *FirstEnergy Complaint*. Therefore, as Mr. Kormos explains, this issue falls in the category of a risk that prudent resource planning must address. As he explains:

Given where we are today, the potential adverse impacts of *EPSA* on Demand Resources simply falls in the category of foreseeable risk. We can reasonably foresee a scenario in which the Supreme Court decides this spring not to review *EPSA*, and FERC concludes, in light of *EPSA*, that it also lacks authority to order compensation for end-users that commit through the wholesale market to reduce peak electricity consumption. We do not need to agree that that is the correct legal conclusion, or that that is the *most likely* scenario (just as planners must be concerned with possible occurrences of extreme weather, or with higher than normal resource outages), to conclude that it is *foreseeable*. And if that scenario does unfold, then the important point from a resource adequacy perspective is that it could effectively negate or nullify the Demand Resource commitments on which the PJM Region is now depending to ensure reliable service to loads beginning in just over five months.⁵

Second, the 2015/2016 Delivery Year is notable for a record level of generation retirements, mostly related to environmental requirements that take effect in spring 2015. This context, coupled with experience this past winter that brought to the fore a concern with performance of some committed capacity resources, raises a resource adequacy concern for the 2015/2016 winter. Specifically, as shown by Mr. Kormos, if PJM were to experience conditions next winter comparable to those seen last winter, then, given the overall reduction in available generation, the PJM Region would have a negative reserve margin, i.e., a loss of load. Again, this is not the most likely scenario, but it is a foreseeable risk, given the reduction in available generation and the forced outage rate actually experienced last winter.

Given these resource adequacy uncertainties for the 2015/2016 Delivery Year, PJM should pursue prudent measures that help minimize or mitigate the consequences of this risk. To that end, PJM has initiated discussions with sellers of generation resources that are not presently available for the 2015/2016 Delivery Year, to investigate the feasibility of making those resources available. This category includes existing generation resources that have previously announced their retirement for the 2015/2016 Delivery Year, and planned generation resources that are scheduled to enter service for the 2016/2017 Delivery Year. PJM is not necessarily looking for a full Delivery Year from these projects; for example, a planned resource might provide sufficient assistance if it could accelerate its in-service date to encompass the prior winter period, while a

⁵ Kormos Aff. ¶ 10.

retiring resource might provide sufficient assistance by extending its service life to encompass the subsequent summer period.

While this possible reliance on out-of-market generator agreements is somewhat similar to the program under Part V of PJM's Tariff to compensate generators that delay their deactivation date, Part V does not provide a solution for the concerns with the 2015/2016 Delivery Year. Part V is meant to address transmission reliability issues. Moreover, Part V deals only with deactivations, so it does not provide a vehicle for agreements with planned resources to accelerate their in-service date.

Consequently, to enable an additional option to, in effect, leave no stone unturned in managing the potential resource adequacy concerns with both the summer and winter periods of the 2015/2016 Delivery Year, PJM proposes to add to RPM a provision that recognizes that PJM can enter into out-of-market agreements for targeted capacity commitments for all or part of that Delivery Year, and to establish that the costs of such agreements will be recovered from Load Serving Entities—in essentially the same way that out-of-market “make-whole” payments to Capacity Market Sellers are currently recovered from Load Serving Entities. Each such agreement will be subject to review and approval by the Commission, but to streamline that process, PJM suggests tariff language to memorialize the standards and considerations for approval of such agreements.

II. BACKGROUND

A. The Present Status of Capacity Resource Commitments for 2015/2016.

As explained by Mr. Kormos, the capacity commitments for the 2015/2016 Delivery Year are notable in at least two respects. First, primarily as a result of new environmental regulations with compliance deadlines that fall less than two months before the start of the Delivery Year, the PJM Region faces an historic level of retirements of existing generation resources.⁶ Over 14,000 megawatts of retirements were announced for 2015/2016 before PJM held the May 2012 BRA to secure capacity

⁶ Kormos Aff. ¶4. The regulations of concern are the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards rule, with a compliance deadline of April 16, 2015, *see* National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9304 (Feb. 16, 2012) (“MATS regulations”) <http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf>, and the New Jersey High Electricity Demand Days rule, with a compliance deadline of May 1, 2015, *see* New Jersey Admin. Code § 7.27-19:30 (establishing 2015 HEDD Emissions Limit Achievement Plan).

for that Delivery Year.⁷ That level of expected retirements has moderated somewhat as we approach the start of the Delivery Year, but still stands at 11,769 megawatts—a level that far outstrips the level of retirements ever announced for any other single year.⁸

Second, PJM has secured a high level of Demand Resources to meet the region's reliability needs for the 2015/2016 Delivery Year. The 2012 BRA cleared over 14,800 megawatts of Demand Resources.⁹ Based on resource replacement activity by Demand Resource providers in the two Incremental Auctions held so far for that Delivery Year, PJM estimates that 11,257 megawatts of Demand Resources will remain committed as of the start of the Delivery Year.¹⁰ That number could drop further as a result of replacements of Demand Resources in the Third Incremental Auction, but the amount of that further decrease is not known, and the reduction in available generation resources (due to the record level of retirements) raises questions about the size of the pool of uncommitted resources that could serve as replacement capacity.¹¹

The May 2012 BRA was also notable in another respect: it cleared 5,350 megawatts in new generation and generation uprates—also a record.¹² But that number, too, has gone down since the BRA. PJM presently estimates that 3,800 megawatts of new generation and uprates will enter service for the 2015/2016 Delivery Year. The drop is primarily due to new plants that cleared the auction for the 2015/2016 Delivery Year but have been delayed into the 2016/2017 Delivery Year.¹³

With the presently expected generation retirements and generation additions, PJM is seeing a net loss of just under 8,000 megawatts of generation resources for the 2015/2016 Delivery Year.¹⁴ But PJM also saw more generator retirements than additions for the 2014/2015 Delivery Year. Looking at the two years together, the cumulative net loss in generation in the PJM Region is 8,359 megawatts. As Mr. Kormos explains, this

⁷ Kormos Aff. ¶¶ 4-5.

⁸ Kormos Aff. ¶ 7.

⁹ Kormos Aff. ¶ 8.

¹⁰ Kormos Aff. ¶ 8.

¹¹ Kormos Aff. ¶ 8.

¹² Kormos Aff. ¶ 7.

¹³ Kormos Aff. ¶ 7. As Mr. Kormos explains, any new generation that cleared the BRA but cannot make the June 1, 2015 in-service date has to obtain replacement capacity, but to the extent that replacement comes from existing generation, it does not change the net loss in overall generation resources. *Id.* ¶ 7 n.2.

¹⁴ Kormos Aff. ¶ 7.

means that “the PJM Region will have 8,359 fewer megawatts of actual generation for the 2015/2016 Delivery Year than it had for the 2013/2014 Delivery Year.”¹⁵

B. *EPSA*, and Further Developments That Have Resulted or Could Result from that Decision, Pose a Threat to the Demand Resources Committed for the 2015/2016 Delivery Year.

EPSA held that the Commission did not have the authority to adopt a rule in Order No. 745¹⁶ prescribing compensation levels for retail customers that seek to provide demand response in wholesale energy markets. As Order No. 745 addressed only energy markets, *EPSA* addressed only the status of compensation for demand response in energy markets. The *EPSA* decision did not purport to decide the Commission’s authority to order or permit compensation for demand response in wholesale capacity markets.

Nonetheless, on the day *EPSA* was issued, the *FirstEnergy Complaint* was filed, asking the Commission to direct PJM to remove all Tariff provisions that allow or require PJM to compensate Demand Resources as a form of supply in the PJM capacity market effective May 23, 2014.¹⁷ The *FirstEnergy Complaint* does not ask the Commission to change the outcome of the RPM Auctions for any Delivery Year before the 2017/2018 Delivery Year, but it does seek a ban on *paying* any Demand Resources for providing capacity for those years, including the 2015/2016 Delivery Year.

PJM answered in opposition to the *FirstEnergy Complaint*, arguing, among other things, that the Commission should not upset the rules for Demand Resources (including those on compensation) already committed through RPM before the complaint was filed.¹⁸ On reply, FirstEnergy has asked the Commission to reject PJM’s arguments, contending, *inter alia*, that *EPSA*, and the complaint, require “eliminat[ing] FERC-regulated payments for demand response resources in the PJM capacity market;” and that

¹⁵ Kormos Aff. ¶ 7.

¹⁶ *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,322, *order on reh’g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh’g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *vacated*, *Elec. Power Supply Ass’n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014)

¹⁷ *Initial FirstEnergy Complaint* at 1-2; *see also Amended FirstEnergy Complaint* at 1, 4, 19-23.

¹⁸ Answer of PJM Interconnection, L.L.C., Docket No. EL14-55-000, at 23-29 (Oct. 22, 2014).

“it is beyond FERC’s jurisdiction to require payments to demand response resources in FERC-approved tariffs.”¹⁹

The D.C. Circuit has stayed²⁰ issuance of its mandate in *EPSA* pending the federal government’s submission to the U.S Supreme Court of a petition for a writ of certiorari—an action the U.S. Solicitor General has advised the Court it will take by January 15, 2015.²¹ The stay will continue in effect until the Supreme Court disposes of any cert. petition. As the Supreme Court’s current term ends around the end of June, it is highly likely that the Supreme Court will act on any cert. petition (assuming one is filed) before, or shortly after, the start of the 2015/2016 Delivery Year on June 1, 2015.

Thus, as matters presently stand, five months from the start of the next Delivery Year on June 1, 2015, there are a number of scenarios that could significantly adversely affect the PJM Region’s reliance on the over 11,000 megawatts of Demand Resources currently committed as capacity. Even if the Solicitor General files a petition for certiorari, the Supreme Court could deny that petition before the start of the Delivery Year, resulting in the issuance of the *EPSA* mandate. Issuance of the *EPSA* mandate could spawn new filings and litigation before the Commission, even beyond the *FirstEnergy Complaint* and a Commission remand proceeding. Energy market payments to demand resources could be nullified. All of this activity could coincide with the 2015 summer peak season. A worst-case, but conceivable, scenario could include a Commission finding, in reaction to an *EPSA* mandate, the *FirstEnergy Complaint*, or other new filings, that the Commission has no authority to approve wholesale market compensation to retail customers that participate in PJM’s capacity market.

¹⁹ Motion for Leave to Answer and Answer of FirstEnergy Service Company, Docket No. EL14-55-000, at 6 (Nov. 14, 2014); *see also id.* at 16 (“*EPSA* squarely holds that FERC lacks jurisdiction to set payments for demand response under FPA sections 201, 205, or 206.”) and at 31 (“the principal relief FirstEnergy has requested is the elimination of unlawful rates paid to demand response providers who are not entitled to any payment in the wholesale capacity market.”).

²⁰ *Elec. Power Supply Ass’n v. FERC*, No. 11-1486 (D.C. Cir. Dec. 15, 2014) (per curiam); *Elec. Power Supply Ass’n v. FERC*, No. 11-1486 (D.C. Cir. Oct. 20, 2014) (per curiam).

²¹ *See FERC v. Elec. Power Supply Ass’n*, S. Ct. No. 14A596, Application of the Solicitor General for an Extension of Time Within Which to File a Petition for a Writ of Certiorari, at 1, (Dec. 5, 2014). The Supreme Court granted the requested extension of time on December 8, 2014. *FERC v. Elec. Power Supply Ass’n*, S. Ct. No. 14A596, Application granted by The Chief Justice extending the time to file until January 15, 2015 (Dec. 8, 2014).

These possible scenarios therefore pose a significant risk that PJM's ability to compensate and retain those resources effectively could be nullified before, or in the midst of, summer 2015. As Mr. Kormos explains, given where we are today, the possible scenarios stemming from the *EPISA* decision fall in the category of "foreseeable risk."²² He notes that "[w]e do not need to agree that that is the correct legal conclusion, or that that is the *most likely* scenario (just as planners must be concerned with possible occurrences of extreme weather, or with higher than normal resource outages) to conclude that it is *foreseeable*."²³ Prudent planning simply must acknowledge and address contingencies such as these, whether they are poor weather or adverse regulatory or judicial outcomes.

As Mr. Kormos shows, if PJM *were* to lose the ability to rely on these committed Demand Resources next summer, the level of committed Capacity Resources would drop significantly below the IRM of 15.6% that was approved for the PJM Region for the 2015/2016 Delivery Year. Specifically, without those Demand Resources, the reserve margin for next summer would drop to 13.2%.²⁴

As Mr. Kormos explains, "[e]ntering next summer with an IRM significantly below 15.6% would raise legitimate resource adequacy concerns."²⁵ That approved IRM was carefully chosen to provide a cushion against loads that are higher than a "normal" peak, or forced outages that are higher than the most likely outage rate. As Mr. Kormos states, "[a] simultaneous occurrence of worse than normal weather and worse than normal outages, therefore (as might occur, for example, if substantial parts of the region suffered extreme heat with highs above 95 degrees on multiple successive workdays), would erode the cushion provided by the approved IRM."²⁶ While PJM's approved IRM "is designed to accommodate just such contingencies," a 13.2% reserve margin "would *not* accommodate those contingencies."²⁷ Mr. Kormos warns that a reserve margin over two percentage points below the approved IRM "would present serious risks that PJM could not serve all loads if the region experienced the more severe conditions that, while not routine, can still be reasonably expected from time to time."²⁸

When confronted with such a foreseeable risk, PJM must take steps to avoid, minimize, or mitigate that risk. As Mr. Kormos explains, if PJM knows that a reserve

²² Kormos Aff. ¶ 10.

²³ Kormos Aff. ¶ 10.

²⁴ Kormos Aff. ¶¶ 13-14.

²⁵ Kormos Aff. ¶ 15.

²⁶ Kormos Aff. ¶ 15.

²⁷ Kormos Aff. ¶¶ 15-16.

²⁸ Kormos Aff. ¶ 16.

margin of only 13.2% “is reasonably foreseeable, then PJM is obliged to pursue prudent measures to prevent that reserve margin from being reduced even further, and to supplement capacity commitments as a protection against that possible drop in the IRM.”²⁹

C. Recent Poor Capacity Performance Raises Distinct Concerns About the Resources Committed for the Winter of 2015/2016.

As Mr. Kormos also notes, “the PJM Region experienced especially poor generator performance in January 2014, with a forced outage rate of 22% during extreme weather in early January, and forced outage rates that were significantly worse than normal (although not as bad as 22%) later in the month.”³⁰ Through its December 12, 2014 filing in Docket No. ER15-623-000, PJM is proposing to remedy market design shortcomings that appear to have contributed to this poor performance because they have failed to provide Capacity Resource owners sufficient incentive to ensure their resources perform.

However, that filing did not address the 2015/2016 Delivery Year, because, as Mr. Kormos explains, “there simply is not enough time before that Delivery Year starts (on June 1, 2015) to implement the plant and infrastructure changes that are needed in the long term to improve generator performance.”³¹ As Mr. Kormos also explains, PJM has been active in identifying, developing, and implementing various measures that can be implemented in the near term to help improve winter operations in light of last winter’s experience.³² But, as he notes, “without changes in generation plant and fuel delivery infrastructure, the near-term measures are necessarily limited, and they have not yet been put to the test by peak winter operations or stressed conditions.”³³ One important question is what impacts on reliability might result if PJM were to experience, in the winter of 2015/2016, conditions similar to those experienced in January 2014.

PJM has considered this question, and has found, as Mr. Kormos relates, that “with the reduced quantity of generation available for the 2015/2016 Delivery Year, if PJM experienced conditions next winter comparable to those seen last winter, the PJM

²⁹ Kormos Aff. ¶ 17.

³⁰ Kormos Aff. ¶ 18.

³¹ Kormos Aff. ¶ 18.

³² Kormos Aff. ¶ 19. A summary and update on these near-term measures was recently considered by the PJM Operating Committee and is available at the following web address: <http://www.pjm.com/~media/commsittees-groups/committees/oc/20141203/20141203-item-12-and-13-hot-and-cold-weather-recommendation-updates.ashx>

³³ Kormos Aff. ¶ 19.

Region would have a negative reserve margin, i.e., a loss of load.”³⁴ Specifically, Mr. Kormos explains, if PJM experienced the type of winter peak that is statistically expected 10% of the time (i.e., comparable to last winter’s peak) while also experiencing forced outages similar to those seen last winter, “then the load would exceed the resources by over 2,600 megawatts;”³⁵ in other words, PJM would be unable to serve all load.

Given these concerns and uncertainties for both the summer and winter of the 2015/2016 Delivery Year, Mr. Kormos counsels that “PJM should pursue prudent measures that (i) avoid worsening the risk and (ii) help minimize or mitigate the consequences of the risk.”³⁶

III. THE PROPOSED TARIFF REVISION IS NECESSARY, AND SHOULD BE APPROVED AS JUST AND REASONABLE.

The Tariff change proposed in this filing is intended to provide PJM with one additional option to address and mitigate the resource adequacy concerns, described above, for the 2015/2016 Delivery Year. To be clear, this Tariff change *is limited to that Delivery Year* and is prompted by the unique resource adequacy concerns that have arisen for that Delivery Year, as detailed above.

To help avoid and minimize those resource adequacy concerns, PJM proposes that it be enabled to pursue agreements, outside the RPM Auctions, with otherwise uncommitted generation resources. As noted above, given the large net drop in generation available for the 2015/2016 Delivery Year, uncommitted resources are most likely to be found among retiring resources that may agree to delay their retirement, and planned resources that may be willing to accelerate their in-service date.

As explained by Mr. Kormos, resources in such circumstances may not be able to commit capacity for a full Delivery Year, “given uncertainties over whether, and when, retiring generators could obtain any necessary approvals or waivers to continue operating, and because planned resources may be able to accelerate their in-service date by only a few months, rather than a full year.”³⁷ These resources also may not be eligible under PJM’s current generation deactivation rules in Part V of the Tariff. Those rules are designed to address transmission system reliability issues, whereas, for the 2015/2016 Delivery Year, additional resources are needed for resource adequacy concerns.

³⁴ Kormos Aff. ¶ 20.

³⁵ Kormos Aff. ¶ 20. Mr. Kormos also notes that, depending on further developments concerning *EPSA*, PJM might be unable to “count on purely voluntary assistance from demand response to help manage peak or emergency conditions next winter.” *Id.*

³⁶ Kormos Aff. ¶ 21.

³⁷ Kormos Aff. ¶ 27.

Moreover, the Part V rules (which concern unit retirement) are not an option for planned resources that may be able to accelerate their in-service dates.

These same considerations indicate that a special auction (i.e., in addition to those presently provided by the Tariff) may offer little advantage in this very unique case. Not only is there the difficulty of matching PJM's needs during the 2015/2016 Delivery Year with the time periods of availability that potential resources could offer, there also is the simple fact that there are so few uncommitted resources available that could participate as supply in a special auction. That relatively thin potential supply might therefore produce little competitive pressure, even if PJM employed a "market" mechanism.

PJM proposes to pursue discussions with such resources, or any other available but uncommitted generation resources, to find the resources that can be deployed on a timely and cost-effective basis to meet the periods of greatest potential need during the 2015/2016 Delivery Year. PJM then will file such agreements with the Commission for case-by-case review and approval. To streamline that process, however, PJM proposes to make clear in the Tariff the purpose for which such agreements would be entered, i.e., to ensure that the PJM Region can continue to satisfy during the 2015/2016 Delivery Year the applicable reliability standards on resource adequacy, taking into account contingencies or concerns affecting previously committed Capacity Resources, such as those described in this filing. Accordingly, PJM proposes to modify Attachment DD, section 5.14, to add new subsection 5.14(b-1), stating as follows:

To address resource adequacy concerns specific to the 2015/2016 Delivery Year (or any part thereof), the Office of the Interconnection may procure, outside an RPM Auction, agreements for capacity from planned or existing generation resources not otherwise committed for that Delivery Year (or the relevant part thereof), but solely to the extent such agreements are needed to help ensure that the PJM Region satisfies applicable reliability standards for resource adequacy, taking into account contingencies or concerns affecting Generation Capacity Resources and/or Demand Resources previously committed for such Delivery Year. Any such agreement shall be subject to approval by the Commission, taking into consideration the extent to which the agreement satisfies the above standards. The costs of payments under such agreements shall be collected pro rata from all LSEs based on such LSEs' Daily Unforced Capacity Obligations.

The fact such agreements will need to be filed with the Commission for acceptance or approval means the Commission will be able to examine specific agreements to make sure that they are just, reasonable and consistent with the standards set forth in new section 5.14(b-1). This approach also will give affected ratepayers and other parties the opportunity to review, comment upon, or protest such agreements.

Finally, new section 5.14(b-1) states that the costs of any payments made pursuant to such agreements shall be collected pro rata from all LSEs, based on such LSEs' Daily

Unforced Capacity Obligations. This is consistent with cost allocation principles, because it ensures that the costs of resource adequacy agreements are borne by the LSEs (and the loads they serve) that benefit from resource adequacy.³⁸ This cost recovery for “out-of-market” resource costs also tracks the cost recovery presently allowed under section 5.14 for other “out-of-market” payments, such as make-whole payments for certain Capacity Resources.³⁹

IV. REQUESTED EFFECTIVE DATE

Consistent with section 35.3 of the Commission’s regulations, 18 C.F.R. § 35.3, PJM requests an effective date of February 23, 2015, i.e., 61 days after the date of this filing.

V. DOCUMENTS SUBMITTED WITH THIS FILING

This filing consists of the following:

1. This transmittal letter;
2. Mr. Kormos’ affidavit, as Attachment A;
3. Revisions to Tariff Attachment DD, section 5.14, in redlined format, as Attachment B; and
4. Revisions to Tariff Attachment DD, section 5.14, in clean format, as Attachment C.

³⁸ See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,323, at PP 504-05 (2011), *order on reh’g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh’g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff’d sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014), *reh’g denied en banc*, 2014 U.S. App. LEXIS 19968 (D.C. Cir. Oct. 17, 2014); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 2006–2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,241 at P 561, *order on reh’g*, Order No. 890-A, 2006–2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,261 (2007), *order on reh’g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh’g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

³⁹ See Attachment DD, sections 5.14(b) and (e).

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,⁴⁰ PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx> with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region⁴¹ alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. 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.

⁴⁰ See 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

⁴¹ PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

VII. COMMUNICATIONS

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

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743 (phone)
(202) 393-7741 (fax)
Craig.Glazer@pjm.com

Jacquelynn Hugee
Assistant General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd
Audubon, PA 19403
(610) 666-8208 (phone)
(610) 666-8211 (fax)
Jacquelynn.Hugee@pjm.com

Barry S. Spector
Paul M. Flynn
David S. Berman
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200 (phone)
(202) 393-1240 (fax)
spector@wrightlaw.com
flynn@wrightlaw.com
berman@wrightlaw.com

Jennifer Tribulski
Senior Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-4363 (phone)
(610) 666-8211 (fax)
Jennifer.Tribulski@pjm.com

VIII. CONCLUSION

For the reasons stated above, PJM requests that the Commission accept or approve the proposed revision to Attachment DD, section 5.14, without modification or condition, to be effective February 23, 2015.

Respectfully submitted,

/s/ Paul M. Flynn

Barry S. Spector
Paul M. Flynn
David S. Berman
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200 (phone)
(202) 393-1240 (fax)
spector@wrightlaw.com
flynn@wrightlaw.com
berman@wrightlaw.com

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743 (phone)
(202) 393-7741 (fax)
Craig.Glazer@pjm.com

Jacquelynn Hugee
Assistant General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd
Audubon, PA 19403
(610) 666-8208 (phone)
(610) 666-8211 (fax)
Jacquelynn.Hugee@pjm.com

Jennifer Tribulski
Senior Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-4363 (phone)
(610) 666-8211 (fax)
Jennifer.Tribulski@pjm.com

December 24, 2014

Attachment A

Affidavit of Michael J. Kormos on Behalf of PJM
Interconnection, L.L.C.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.)

Docket No. ER15-____-000

**AFFIDAVIT OF MICHAEL J. KORMOS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

1. My name is Michael J. Kormos. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently am employed by PJM Interconnection, L.L.C. (“PJM”), serving as its Executive Vice President – Operations. I am submitting this affidavit on behalf of PJM in support of its filings for a tariff waiver, and a tariff change, needed to help PJM better manage significant uncertainty affecting resource adequacy in the PJM Region during the 2015/2016 Delivery Year, i.e., the twelve-month period that begins June 1, 2015.

2. I have had overall responsibility for PJM system operations for over eleven years, in both my current role as Executive Vice President–Operations and my prior position as Vice President of System Operations. In my present capacity I am responsible for all services that touch reliability, including system operations, system planning, information and technology services, and security and regional coordination. Before my promotion to Vice President of System Operations, I served for fifteen years in engineering and management positions of increasing responsibility in PJM’s Operations Division. I have been a member of the North American Electric Reliability Corporation (“NERC”) operating committee and the Board of Directors for the ReliabilityFirst Corporation. I currently sit on the Executive Committee of the Eastern Interconnection Planning Collaborative and the Board of Directors for the Eastern Interconnection Data Sharing Network, Inc. I hold a Bachelor of Science degree in electrical engineering from Drexel University and a Master of Business Administration degree from Villanova University.

Capacity Resources Committed for the 2015/2016 Delivery Year.

3. PJM secures capacity commitments through its forward auctions for a Delivery Year that runs from June 1 of a calendar year to May 31 of the next calendar year. The 2015/2016 Delivery Year will begin in a little over five months from now, i.e., on June 1, 2015. I should emphasize at the outset that PJM’s Reliability Pricing Model (“RPM”) auctions have been successful in securing enough Capacity Resources for the 2015/2016 Delivery Year to satisfy the Installed Reserve Margin (“IRM”) established for that year. Nonetheless, resource adequacy concerns for summer 2015 have arisen because a federal court decision has called into question PJM’s ability to compensate and rely upon the large quantity of Demand Resources that are part of those committed Capacity Resources. PJM also has concerns about winter 2015/2016 resource adequacy in light of a very high level of generation retirements for that Delivery Year, shortcomings in generator performance revealed by last winter’s extreme weather, and the limited amount of time between now and the 2015/2016 winter for the plant and

infrastructure changes needed in the long term for improvements in generator performance.

4. PJM conducted the Base Residual Auction to secure capacity for the 2015/2016 Delivery Year in May 2012. As PJM explained in its report on that auction, the auction results were impacted by a series of significant developments. Most notably, PJM explained, “an unprecedented amount, over 14,000 MW, of generation retirements have been announced driven largely by environmental regulations, primarily EPA Mercury and Air Toxics Standards (MATS) and the High Electricity Demand Day Rule (HEDD) in New Jersey which have compliance deadlines of April 16, 2015 and May 1, 2015 respectively.”¹ Driven by these retirements, the 2012 Base Residual Auction results showed a significant decline in the amount of coal-fired generation committed as capacity in PJM.

5. This substantial decline in capacity commitments in the Base Residual Auction from existing generation resources was offset by commitments from new generation resources and, especially, by commitments from a record megawatt quantity of Demand Resources and Energy Efficiency Resources. The 2012 BRA cleared approximately 4,900 megawatts of new generation and approximately 450 megawatts of generation uprates. The BRA also cleared over 14,800 megawatts of Demand Resources, and over 900 megawatts of Energy Efficiency Resources. The combined Demand and Energy Efficiency Resources were the most PJM has ever cleared in any BRA, then or since. And the existing generation resource retirements announced for 2015/2016 prior to that BRA were by far the greatest quantity of retirements for any single Delivery Year.

6. In the two-and-a-half years since the May 2012 BRA, the retirements, new generation, and expected Demand Resources for the 2015/2016 Delivery Year all have decreased somewhat from the levels expected at the time of the BRA. But the 2015/2016 Delivery Year still has an extraordinary level of retirements of existing generation resources, and still depends on a very high level of expected commitments by Demand Resources.

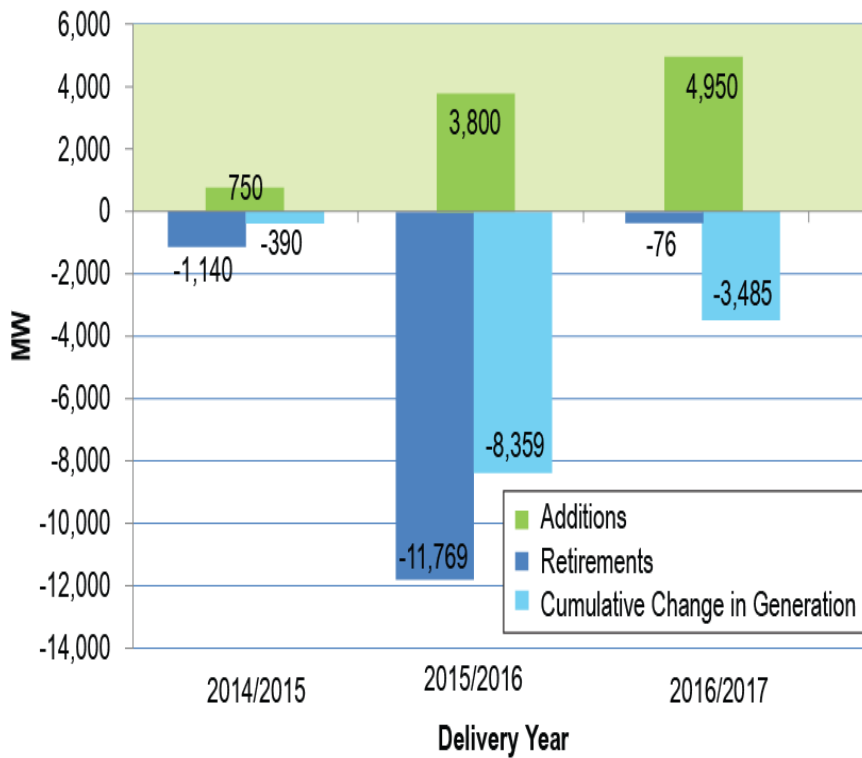
7. The bar chart below shows the net change in generation for 2015/2016 and places it in context by showing the immediately prior and succeeding Delivery Years, as well as the cumulative net change in generation over those three Delivery Years. The 2015/2016 Delivery Year clearly stands out for its very large net drop in actual generation. PJM presently expects 11,769 megawatts of existing generation resources to retire for the 2015/2016 Delivery Year, and 3,800 megawatts of generation to be added in time for the 2015/2016 Delivery Year.² The net loss of generation of a little under 8,000

¹ 2015/2016 RPM Base Residual Auction Results, PJM Interconnection, L.L.C., 2 (May 18, 2012), <http://www.pjm.com/~media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx>.

² The drop from the 5,350 MWs of new generation and uprates cleared in the BRA, to the 3,800 MWs expected today, reflects delays in some of those expected additions, primarily two new combined cycle gas units, into the 2016/2017 (continued . . .)

megawatts, when considering only the retirements and additions for 2015/2016, increases to a cumulative net loss of 8,359 megawatts of generation when the net generation loss from 2014/2015 (which also saw more generator retirements than additions) is considered. That cumulative net loss means the PJM Region will have 8,359 fewer megawatts of actual generation for the 2015/2016 Delivery Year than it had for the 2013/2014 Delivery Year. By contrast, PJM expects a substantial net addition of generation for the 2016/2017 Delivery Year. Only 76 megawatts of generator retirements have been announced for that year, versus 4,950 megawatts of generator additions that have been committed so far for that year. This will reduce, by more than half, the cumulative net loss in generation carried over from 2015/2016.

**Annual and Cumulative Changes in Generation Resources
2014/2015 Through 2016/2017**



8. Demand Resource commitments for the 2015/2016 Delivery Year, while expected to be down from the level committed in the BRA, remain at a very high level. Based on replacement capacity purchased by demand response providers in the two Incremental Auctions already held for 2015/2016, PJM now estimates that 11,257

(. . . continued)

Delivery Year. Any new generation that cleared the BRA but cannot make the June 1, 2015 in-service date has to obtain replacement capacity, but to the extent that replacement comes from existing generation, it does not change the net loss in overall generation resources shown here.

megawatts of Demand Resources likely will be committed for the 2015/2016 Delivery Year. Based on historic experience, some of the presently estimated 11,257 megawatts of Demand Resources will be replaced in next February's Third Incremental Auction for the 2015/2016 Delivery Year. But with the very large net drop in generation resources for 2015/2016 (described above), there is not likely to be much generation that is uncommitted and available to serve as replacement capacity in the Third Incremental Auction. Therefore, it seems likely that PJM will begin the 2015/2016 Delivery Year relying on Demand Resources at something like the currently expected level of 11,257 megawatts.

Risk to Demand Resource Commitments From the *EPSA* Decision.

9. The substantial net reduction in generation resource commitments for the forthcoming Delivery Year, and corresponding heavy reliance on Demand Resources, raises resource adequacy concerns in light of the May, 2014 federal court decision in *Electric Power Supply Ass'n v. FERC*.³ That decision, as I understand it, held that FERC does not have the authority to approve rules on compensation in the wholesale energy market for retail customers that agree to consume less electricity. After that decision was issued, the First Energy Companies filed a complaint, still pending before FERC,⁴ challenging all of PJM's current tariff rules that provide for Demand Resources to serve as supply in PJM's capacity market. While PJM has argued to FERC that neither the *EPSA* decision nor the FE Complaint should result in any changes to the commitment or compensation of Demand Resources for the 2015/2016 Delivery Year, PJM has been advised by counsel that there is a significant risk that the *EPSA* precedent, if not reversed by the U.S. Supreme Court, could be extended to negate PJM's ability to compensate end-users that commit through the capacity market to reduce their peak electricity consumption, and that PJM has little control over when such a decision would become effective. In that regard, I understand that the United States Solicitor General has stated that his office will ask the Supreme Court to review the *EPSA* decision, and I am advised by counsel that the Supreme Court is very likely to decide before the start of the 2015-2016 Delivery Year whether to review that case.

10. While the course of events on demand response (with FERC, PJM, and countless stakeholders and market participants assuming for years that it was a valid wholesale energy market product, before a federal appeals court concluded, in a sweeping decision, that it is not) has been highly unusual, the appropriate perspective *today* on this question for purposes of resource adequacy planning is neither unusual nor controversial. Given where we are today, the potential adverse impacts of *EPSA* on Demand Resources simply fall in the category of foreseeable risk. We can reasonably foresee a scenario in which the Supreme Court decides this spring not to review *EPSA*, and FERC concludes, in light of *EPSA*, that it also lacks authority to order compensation for end-users that

³ 753 F.3d 216 (D.C. Cir. 2014) ("*EPSA*").

⁴ Complaint of FirstEnergy Service Company, Docket No. EL14-55-000 (May 23, 2014) ("*FE Complaint*").

commit through the wholesale market to reduce peak electricity consumption. We do not need to agree that that is the correct legal conclusion, or that that is the *most likely* scenario (just as planners must be concerned with possible occurrences of extreme weather, or with higher than normal resource outages) to conclude that it is *foreseeable*. And if that scenario does unfold, then the important point from a resource adequacy perspective is that it could effectively negate or nullify the Demand Resource commitments on which the PJM Region is now depending to ensure reliable service to loads beginning in just over five months.

11. Therefore, the prudent response to this presently foreseeable risk is to assess the impacts on resource adequacy, should the risk be realized, and to consider measures that would mitigate the consequences of the occurrence of that risk, as discussed below.

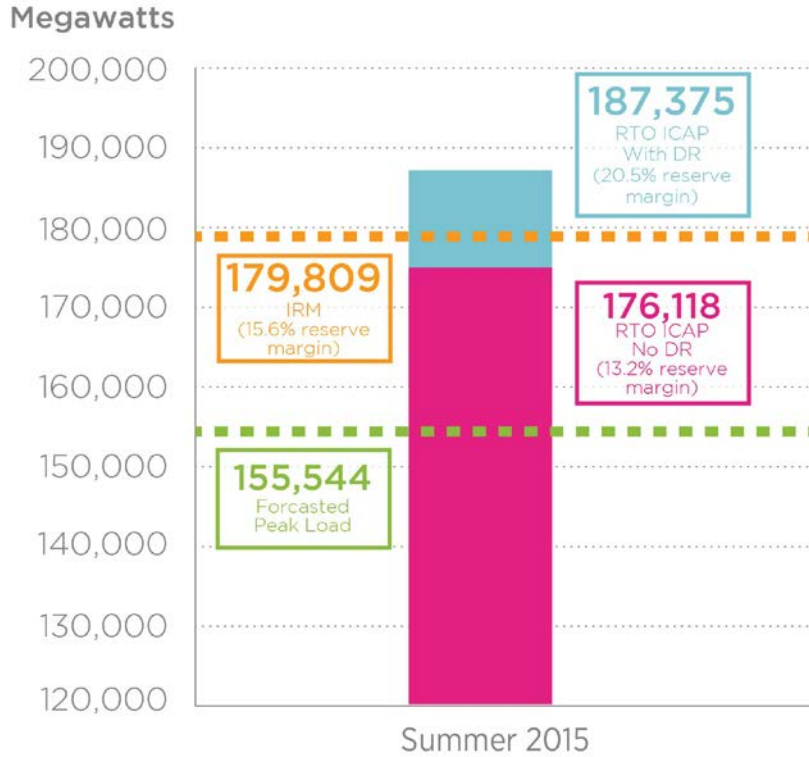
Resource Adequacy Consequences of Negation of Demand Resource Commitments.

12. In light of this foreseeable risk, PJM has assessed the impact on resource adequacy if the presently committed Demand Resources became unavailable for use in the 2015/2016 Delivery Year. As seen in the graph below, loss of these resources would place the PJM Region's resource level below the IRM that was established to assure reliable service to loads during next summer's peak season.

13. Specifically, PJM's latest peak load forecast for the PJM Region for summer 2015 is 155,544 MWs. The IRM that was duly established for the 2015/2016 Delivery Year is 15.6%, meaning that the peak load plus reserves level that PJM uses to determine the region's capacity needs is 179,809 MWs.

14. The current resource commitment, including Demand Resources and Energy Efficiency Resources, for the 2015/2016 Delivery Year is 187,375 MWs, which provides a reserve margin of 20.5%. However, Demand Resources account for 11,257 MWs of that resource commitment. If those Demand Resource commitments became invalid, the level of resources committed for the 2015/2016 Delivery Year would drop to 176,118MWs. That would correspond to a reserve margin of only 13.2%, well below the established IRM of 15.6%. In fact, any loss of approximately 7,500 or more MWs of the current Demand Resource commitment would place the PJM Region below the established IRM.

Resource Adequacy Shortfall without Demand Resources Summer 2015



15. Entering next summer with an IRM significantly below 15.6% would raise legitimate resource adequacy concerns. For 2015 (like any other year) PJM uses a “50/50” summer peak load forecast, i.e., a forecast that has a 50% chance of being exceeded if weather or other conditions are more severe than normal. The 15.6% IRM is selected, in part, to accommodate the risk that peak conditions could be more extreme than normal. Similarly, the PJM Region’s historical experience shows that a generator forced outage rate of about 7% is statistically “normal.” The approved IRM of 15.6% therefore is effectively a reserve of 8% to 9% after accounting for a “normal” level of forced outages. But PJM’s historical experience also shows that worse, even significantly worse, forced outages can be expected periodically. A simultaneous occurrence of worse than normal weather and worse than normal outages, therefore (as might occur, for example, if substantial parts of the region suffered extreme heat with highs above 95 degrees on multiple successive workdays), would erode the cushion provided by the approved IRM.⁵ PJM’s IRM is designed to accommodate just such

⁵ It is worth noting that PJM also might have fewer options to rely on neighboring systems during the 2015/2016 Delivery Year. For example, while PJM does not
(continued . . .)

contingencies, while avoiding overly conservative assumptions that would increase costs to loads without materially improving reliability.

16. But a reserve margin of only 13.2% (i.e., the margin if Demand Resources became unavailable) would *not* accommodate those contingencies. The 15.6% reserve margin is supported by PJM analyses showing it would be expected to result in no more than one loss of load event in ten years. By contrast, a reserve margin of only 13.2% would be expected to result in a loss of load event every 4.5 years. Thus, a reserve margin of 13.2% would present serious risks that PJM could not serve all loads if the region experienced the more severe conditions that, while not routine, can still be reasonably expected from time to time.

17. Put more simply, the region's carefully considered Installed Reserve Margin is 15.6%, not 13.2%, because the approved IRM is considered necessary to ensure reliable service to loads. If PJM knows, going into the Delivery Year, that a reserve margin of only 13.2% is reasonably foreseeable, then PJM is obliged to pursue prudent measures to prevent that reserve margin from being reduced even further, and to supplement capacity commitments as a protection against that possible drop in the IRM. PJM proposes just such measures in these two filings, as I discuss later in my affidavit.

Recent Experience with Poor Generator Performance, Combined with Relatively Lower Levels of Generation Commitment for 2015/2016, Raise Concerns for the Winter of 2015/2016.

18. As has been well documented elsewhere,⁶ the PJM Region experienced especially poor generator performance in January 2014, with a forced outage rate of 22% during extreme weather in early January, and forced outage rates that were significantly worse than normal (although not as bad as 22%) later in the month. That experience has highlighted deficiencies in the RPM market design that are failing to provide Capacity Resource owners sufficient incentive to ensure their resources perform. PJM has proposed a package of reforms through its December 12, 2014 filing in Docket No. ER15-623-000 to remedy those deficiencies. But that filing did not address the 2015/2016 Delivery Year, because there simply is not enough time before that Delivery Year starts (on June 1, 2015) to implement the plant and infrastructure changes that are needed in the long term to improve generator performance.

(. . . continued)

have specific information on summer 2015 resources and reserves for the Midcontinent Independent System Operator, Inc. ("MISO"), NERC's Summer 2014 Reliability Assessment reported that, due to retirements and other issues, MISO's summer reserve margin dropped substantially from 2013 to 2014.

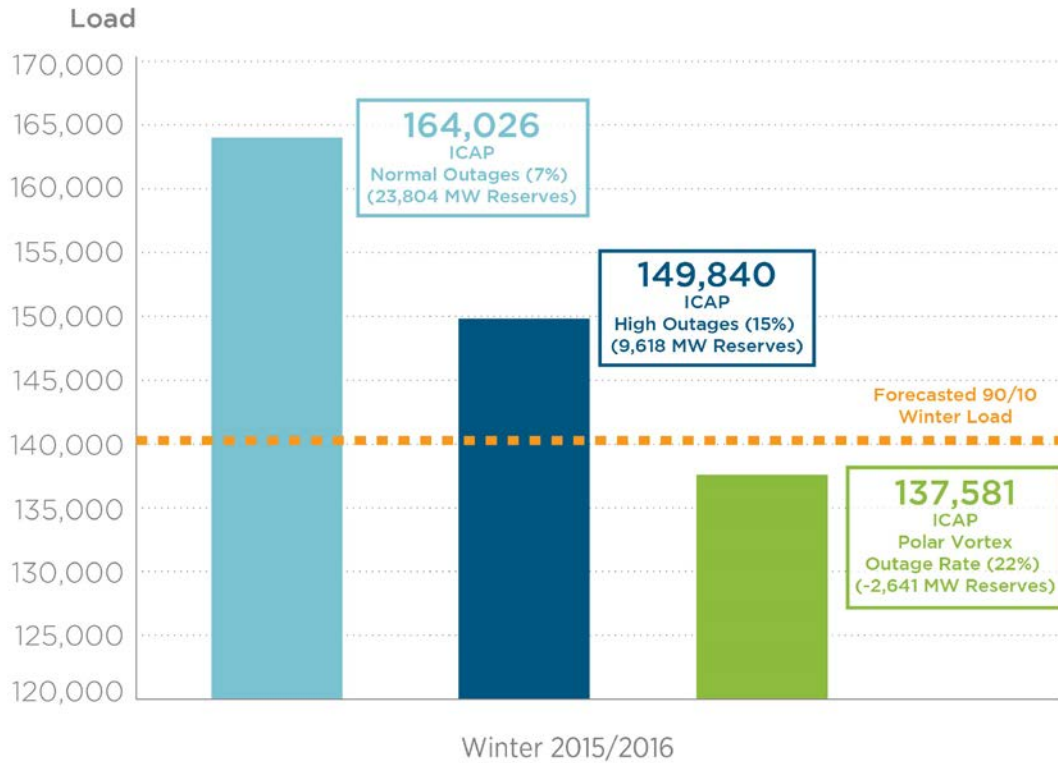
⁶ See, e.g., *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, PJM Interconnection, L.L.C., 4, 24-26 (May 8, 2014), <http://pjm.com/~media/documents/reports/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx>.

19. PJM has been active in identifying, developing, and implementing various measures that can be implemented in the near term to help improve winter operations in light of last winter's experience.⁷ But without changes in generation plant and fuel delivery infrastructure, the near-term measures are necessarily limited, and they have not yet been put to the test by peak winter operations or stressed conditions. In the meantime, we know, from the extraordinary level of generation retirements, that the PJM Region will have over 8,000 fewer megawatts of generation for the 2015-2016 Delivery Year than PJM had during the 2013/2014 Delivery Year, i.e., the year that included last winter. These circumstances add to the level of uncertainty about resource adequacy for the 2015/2016 Delivery Year.

20. In particular, with the reduced quantity of generation available for the 2015/2016 Delivery Year, if PJM experienced conditions next winter comparable to those seen last winter, the PJM Region would have a negative reserve margin, i.e., a loss of load. Specifically, as illustrated in the bar chart below, if the system had a "90/10" winter peak, i.e., a peak statistically expected 10% of the time (the January 2014 winter peak was actually a little worse than that) and a level of forced outages like that seen last winter (i.e., 22%), then the load would exceed the resources by over 2,600 megawatts. While a 22% forced outage rate is extreme, forced outages at or above that level happened on more than one occasion last winter.⁸ PJM's analysis assumes that Annual Demand Resources are *unavailable*, as a consequence of further developments concerning the *EPSA* decision, but PJM assumes that the benefit of committed Energy Efficiency Resource measures remains available, as those typically are permanent equipment or process changes. Some may point out that demand response helped PJM manage the emergency conditions last January, even though most of it was not committed as winter capacity for that Delivery Year. But if as a result of the *EPSA* decision, demand response obtains no compensation from the energy market, it seems unlikely that PJM could count on purely voluntary assistance from demand response to help manage peak or emergency conditions next winter.

⁷ The PJM Operating Committee recently reviewed these efforts and their current status, as shown by the spreadsheet considered by the committee and posted at the following address: <http://www.pjm.com/~media/commsittees-groups/committees/oc/20141203/20141203-item-12-and-13-hot-and-cold-weather-recommendation-updates.ashx>

⁸ For comparison purposes, the chart shows other forced outage scenarios, i.e., a "normal" scenario (with 7% forced outages) and a "high" scenario (with 15% forced outages). Under these two scenarios, PJM retains enough resources to serve the "90/10" winter peak load.



21. Given these concerns and uncertainties, for both the summer and winter of the 2015/2016 Delivery Year, PJM should pursue prudent measures that (i) avoid worsening the risk and (ii) help minimize or mitigate the consequences of the risk. The tariff measures PJM proposes in the two filings described below are two such measures.

PJM’s Narrowly Tailored Tariff Relief Will Help It Manage the 2015/2016 Resource Adequacy Concerns.

22. PJM seeks narrow tariff relief on two fronts to help it manage the resource adequacy concerns that are specific to the 2015/2016 Delivery Year.

23. First, PJM is asking for a waiver of a current RPM market rule that requires PJM to offer to release some previously committed capacity in an Incremental Auction if the Reliability Requirement decreases by a certain amount due to a reduction in the latest updated peak load forecast (compared to the load forecast used for the prior auctions for that Delivery Year). PJM has completed its final peak load forecast for the 2015/2016 Delivery Year, and it posted that forecast last month for review by the stakeholders’ Load Analysis Subcommittee. Based on that forecast, and applying the factors required by the RPM tariff rules, PJM has calculated that it is required to offer to

release approximately 2,000 MWs of capacity previously committed for the 2015/2016 Delivery Year.⁹

24. This would be imprudent, given the resource adequacy concerns I have described above. If PJM released the approximately 2,000 MWs required by the tariff, and then lost the use of the committed Demand Resources, then the reserve margin entering the 2015 summer would be approximately 11.2%—far below the 15.6% found necessary by PJM’s planners and approved by the PJM Board of Managers. In fact, an 11.2% reserve margin is equivalent to a loss of load expectation of one event in every two to three years. Moreover, release of the approximately 2,000 MWs of capacity would heighten the winter 2015/2016 uncertainty that is already present from the historic level of generation retirements and the recent experience of poor winter performance.

25. The RPM Tariff’s automatic requirement for a capacity release offer is concerned solely with changes in load; it does not consider changes in supply at all. That automatic tariff rule therefore certainly does not contemplate the extraordinary changes on the supply side seen in the 2015/2016 Delivery Year, such as the record level of generation retirements, and the significant uncertainty over the status of the large quantity of Demand Resources committed for that year. The Commission should recognize those extraordinary conditions, and the inherent limits in the capacity release rule’s design, and grant PJM relief from that rule.

26. Second, as a result of the generation retirements announced for the 2015/2016 Delivery Year, coupled with the commitment to date of Generation Capacity Resources through the Base Residual Auction, First Incremental Auction, and Second Incremental Auction, there is not much generation in the PJM Region left to commit. PJM therefore has begun to reach out to generators that have announced their intent to retire, and to planned generators that have committed for subsequent Delivery Years, to determine if any of them are capable of committing, and are willing to commit under reasonable terms, for all or part of the 2015/2016 Delivery Year.

27. Resources in such circumstances may not be in a good position to commit capacity for a full Delivery Year, given uncertainties over whether, and when, retiring generators could obtain any necessary approvals or waivers to continue operating, and because planned resources may be able to accelerate their in-service date by only a few months, rather than a full year. Consequently, these resources may be unable to offer to commit in PJM’s Third Incremental Auction for the 2015/2016 Delivery Year. These resources also may not be eligible under PJM’s current generation deactivation rules, which provide for a compensated delay in deactivation for resources that are needed to

⁹ While PJM’s megawatt offer quantity can be calculated now, the financial consequences to load will depend upon the clearing prices in the Third Incremental Auction. In the past, capacity releases in the incremental auctions typically have reduced, but have not eliminated, the dollar amounts that loads were committed to pay due to the clearing of that capacity in a prior auction.

continue in service to address transmission system reliability issues. These resources are needed for resource adequacy concerns, and not transmission system reliability concerns. In addition, the generator deactivation (i.e., retirement) rules are not an option for planned resources that may be able to accelerate their in-service dates.

28. PJM therefore is proposing to add a temporary mechanism to its RPM rules to recover from Load Serving Entities the cost of capacity agreements entered into outside the RPM Auctions for the specific purpose of addressing resource adequacy concerns for the 2015/2016 Delivery Year. Under PJM's proposal, each such agreement will be subject to approval by FERC on a case-by-case basis, if it meets a specified standard of helping PJM satisfy relevant reliability standards for resource adequacy, taking into account concerns and contingencies such as those I have described in this affidavit.

29. This option is not a panacea. Rather, it would simply support PJM's efforts to find supplemental capacity options under the unique conditions of the 2015/2016 Delivery Year where not much capacity in the region remains available, and where there is a foreseeable risk of loss of the Demand Resources that comprise a significant portion of the capacity committed for this Delivery Year.

30. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

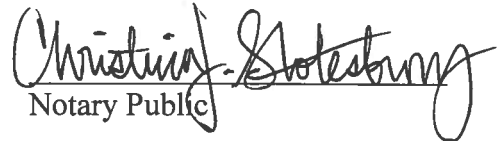
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Docket No. ER15-__-000

Michael J. Kormos, being first duly sworn, deposes and states that he is the Michael J. Kormos referred to in the document entitled "Affidavit of Michael J. Kormos," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief in this proceeding.


Michael J. Kormos

Subscribed and sworn to before me, the undersigned notary public, this 23 day of December, 2014.


Notary Public

My Commission expires: March 2, 2016



COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Christina J. Stotesbury, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires March 2, 2016
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Attachment B

Revisions to Sections of the
PJM Open Access Transmission Tariff
(Marked / Redline Format)

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

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

b) Resource Make-Whole Payments

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

b-1)

To address resource adequacy concerns specific to the 2015/2016 Delivery Year (or any part thereof), the Office of the Interconnection may procure, outside an RPM Auction, agreements for capacity from planned or existing generation resources not otherwise committed for that Delivery Year (or the relevant part thereof), but solely to the extent such agreements are needed to help ensure that the PJM Region satisfies applicable reliability standards for resource adequacy, taking into account contingencies or concerns affecting Generation Capacity Resources and/or Demand Resources previously committed for such Delivery Year. Any such agreement shall be subject to approval by the Commission, taking into consideration the extent to which the agreement satisfies the above standards. The costs of payments under such agreements shall be collected pro rata from all LSEs based on such LSEs' Daily Unforced Capacity Obligations.

c) New Entry Price Adjustment

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

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

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

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

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

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

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).
- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price

for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and
- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and
- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

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

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

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

d) Qualifying Transmission Upgrade Payments

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

e) Locational Reliability Charge

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

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

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

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as

replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

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

g) Resource Substitution Charge

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

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

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

(2) *Applicability.* A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including Repowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle *technology*) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this

subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility (as defined in Part 292 of FERC’s regulations), where the Capacity Market Seller is the owner of the Qualifying Facility or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

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

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

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

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue

estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above, except that the heat rate assumed for the combined cycle resource shall be 8.7 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3,198 per MW-year.

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

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

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

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a *Vertically Integrated Utility* and the MOPR Screened Generation Resource is planned consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

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

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is

satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW
Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

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

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

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

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

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

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

vii) For purposes of the Self-Supply Exemption:

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

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

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

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

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

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

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

(H) “Owned and Contracted Capacity” includes all of the Self-Supply LSE’s qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the

beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

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

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

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

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

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal

government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

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

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

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

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs,

and other fixed O&M and administrative or general costs; financing documents for construction—period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer. The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

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

(9) Exemption/Exception Process.

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

ii) The Capacity Market Seller must submit its request for a Unit-Specific Exception, Competitive Entry Exemption or a Self-Supply Exemption in writing

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

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

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

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

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

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

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

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the

above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

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

Export Customer's Allocated Share equals

$(\text{Export Path Import} * \text{Export Reserved Capacity}) /$

$(\text{Export Reserved Capacity} + \text{Daily Unforced Capacity Obligations of all LSEs in such Zone}).$

Where:

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

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

(3) Distribution of Revenues

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

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

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

A. This transition provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years

(hereafter, “Transition Delivery Years” and each a “Transition Delivery Year”) by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a “Qualified DR Provider.”

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission’s order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this section 5.14A. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this section 5.14A to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer’s peak load contribution during Emergency Load Response dispatch events or tests.

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

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

Where:

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

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

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

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

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJM Settlement during the relevant Transition Delivery Year.

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

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

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

obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this section 5.14A shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJM Settlement in the same manner as described in paragraphs B.2. and B.3. of this section 5.14A, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

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

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

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures,

for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

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

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

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

A. This transition provision applies only to Demand Resources for which a Curtailment

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

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the Affected Demand Resource, of the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year, by type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR) and by Zone or sub-Zone, by the applicable deadline as follows:

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

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

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

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable

Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

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

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

Attachment C

Revisions to Sections of the
PJM Open Access Transmission Tariff
(Clean Format)

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

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

b) Resource Make-Whole Payments

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

b-1)

To address resource adequacy concerns specific to the 2015/2016 Delivery Year (or any part thereof), the Office of the Interconnection may procure, outside an RPM Auction, agreements for capacity from planned or existing generation resources not otherwise committed for that Delivery Year (or the relevant part thereof), but solely to the extent such agreements are needed to help ensure that the PJM Region satisfies applicable reliability standards for resource adequacy, taking into account contingencies or concerns affecting Generation Capacity Resources and/or Demand Resources previously committed for such Delivery Year. Any such agreement shall be subject to approval by the Commission, taking into consideration the extent to which the agreement satisfies the above standards. The costs of payments under such agreements shall be collected pro rata from all LSEs based on such LSEs' Daily Unforced Capacity Obligations.

c) New Entry Price Adjustment

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

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

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

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

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

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

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).
- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price

for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and
- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and
- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

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

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

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

d) Qualifying Transmission Upgrade Payments

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

e) Locational Reliability Charge

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

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

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

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as

replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

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

g) Resource Substitution Charge

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

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

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

(2) *Applicability.* A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including Repowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle *technology*) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this

subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility (as defined in Part 292 of FERC’s regulations), where the Capacity Market Seller is the owner of the Qualifying Facility or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

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

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

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

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue

estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above, except that the heat rate assumed for the combined cycle resource shall be 8.7 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3,198 per MW-year.

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

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

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

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a *Vertically Integrated Utility* and the MOPR Screened Generation Resource is planned consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

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

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is

satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW
Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

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

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

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

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

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

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

vii) For purposes of the Self-Supply Exemption:

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

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

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

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

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

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

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

(H) “Owned and Contracted Capacity” includes all of the Self-Supply LSE’s qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the

beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

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

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

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

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

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal

government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

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

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

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

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs,

and other fixed O&M and administrative or general costs; financing documents for construction—period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer. The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

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

(9) Exemption/Exception Process.

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

ii) The Capacity Market Seller must submit its request for a Unit-Specific Exception, Competitive Entry Exemption or a Self-Supply Exemption in writing

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

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

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

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

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

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

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

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the

above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

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

Export Customer's Allocated Share equals

$(\text{Export Path Import} * \text{Export Reserved Capacity}) /$

$(\text{Export Reserved Capacity} + \text{Daily Unforced Capacity Obligations of all LSEs in such Zone}).$

Where:

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

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

(3) Distribution of Revenues

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

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

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

A. This transition provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years

(hereafter, “Transition Delivery Years” and each a “Transition Delivery Year”) by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a “Qualified DR Provider.”

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission’s order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this section 5.14A. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this section 5.14A to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer’s peak load contribution during Emergency Load Response dispatch events or tests.

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

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

Where:

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

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

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

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

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

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

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

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

obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this section 5.14A shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJM Settlement in the same manner as described in paragraphs B.2. and B.3. of this section 5.14A, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

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

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

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures,

for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

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

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

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

A. This transition provision applies only to Demand Resources for which a Curtailment

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

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the Affected Demand Resource, of the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year, by type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR) and by Zone or sub-Zone, by the applicable deadline as follows:

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

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

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

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable

Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

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

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