

**BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket No. ER18-____-000

**Capacity Repricing or in the Alternative MOPR-Ex Proposal:
Tariff Revisions to Address Impacts of State Public Policies
on the PJM Capacity Market**

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

Paul M. Flynn
Ryan J. Collins
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200 (phone)
(202) 393-1240 (fax)
flynn@wrightlaw.com
collins@wrightlaw.com

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

Chenchao Lu
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-2255 (phone)
(610) 666-8211 (fax)
Chenchao.Lu@pjm.com

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1200 G Street, N.W., Suite 600
Washington, D.C. 20005-3898
Phone: 202.393.1200
Fax: 202.393.1240
wrightlaw.com

April 9, 2018

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. ER18-____-000
Capacity Repricing or in the Alternative MOPR-Ex Proposal:
PJM Tariff Revisions to Address Impacts of State Public Policies
on the PJM Capacity Market.

PJM Interconnection, L.L.C. (“PJM”), pursuant to section 205 of the Federal Power Act (“FPA”), 16 U.S.C. § 824d, hereby submits revisions to the Reliability Pricing Model (“RPM”) rules in the PJM Open Access Transmission Tariff (“Tariff”) to establish the appropriate federal and regional transmission organization (“RTO”) response to address supply-side state subsidies and their impact on the determination of just and reasonable prices in the PJM capacity market.¹

Last month, addressing similar concerns in ISO New England, Inc., the Commission drew from its prior precedent several “first principles” of capacity markets, explaining that the ultimate goal of such markets “is to produce a level of investor

¹ Capitalized terms not otherwise defined herein have the meaning specified in, as applicable, the Tariff, the Reliability Assurance Agreement among Load-Serving Entities in the PJM Region (“RAA”), and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.

confidence that is sufficient to ensure resource adequacy at just and reasonable rates.”² The Commission strongly affirmed that where “participation of resources receiving out-of-market state revenues undermines those principles,” it is the Commission’s “duty under the FPA to take actions necessary to assure just and reasonable rates.”³

As shown in this filing, the PJM capacity market has advanced those “first principles,” by, in particular, meeting the Commission’s stated goals of “facilitat[ing] robust competition for capacity supply obligations;” “provid[ing] price signals that guide the orderly entry and exit of capacity resources;” and “shift[ing] risk as appropriate from customers to private capital.”⁴

PJM’s capacity market, the RPM, has facilitated a impressive degree of resource entry and exit in a relatively short time. Since the inception of RPM in 2007, 50,792 megawatts (“MW”) of new generation capacity has been added, 39,640 MW of generation capacity has retired or been derated, and 9,485 MW of new Demand Resources and 2,063 MW of new Energy Efficiency Resources were offered over the course of those fourteen Delivery Years.⁵ RPM has helped manage “the orderly entry and exit of capacity resources” in the PJM Region during highly consequential (and challenging) changes in environmental regulations and fuel prices over this time period.

² *ISO New England, Inc.*, 162 FERC ¶ 61,205, at P 21 (2018) (“CASPR Order”).

³ *Id.*

⁴ *Id.*

⁵ *2020/2021 RPM Base Residual Auction Results*, PJM Interconnection, L.L.C., 19 (May 23, 2017), <http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en> (“2020/2021 RPM BRA Report”).

Fulfilling another of the Commission's enunciated "first principles," RPM has committed capacity in a way that "shift[s] risk . . . from customers to private capital."⁶ PJM estimates that a significant majority of new entry over this period came from merchant generation firms, such that approximately 75% of the total generation in PJM is now merchant generation. Under the merchant model, the financial and operational risks associated with this generation are shifted from customers to the investors in those plants. And the owners of this generation depend almost entirely on PJM's various markets to support their investment.

Similarly, RPM has "facilitate[d] robust competition for capacity supply obligations,"⁷ as reflected by: (1) strong new entry despite relatively flat demand, (2) introduction of highly efficient generation resources, (3) wide reliance on innovative financing, (4) an open platform for new resource types, and (5) the undeniable resulting financial pressures on capacity supply providers.

Now, however, as detailed in this filing, the PJM Region is seeing increased "participation of resources receiving out-of-market state revenues," which, in the same way noted by the Commission last month for the ISO New England region, threatens to "undermines those principles" in the PJM Region.⁸ Consequently, just as action was required in ISO New England, the "duty under the FPA" that the Commission recognized there also arises in the PJM Region to support those principles, and "take actions necessary to assure just and reasonable rates."⁹

⁶ CASPR Order at P 21.

⁷ *Id.*

⁸ *Id.*

⁹ *Id.*

Absent an appropriate federal response, if a state selectively subsidizes certain resources while still depending on the wholesale capacity market to meet its overall resource adequacy needs, that state's actions impact:

- not only capacity resources excluded from the state out-of-market revenue program (that perversely end up funding some or all of the support offered their competitors),
- but also other states that may not embrace the subsidizing state's particular policy preference.

In short, if a material fraction of resources price their capacity offers relying on their selective receipt of subsidies, then:

- other sellers in PJM's interstate market that do not receive subsidies will receive an artificially suppressed, unjust and unreasonable rate;
- competitive entry will face a significant added barrier;
- new subsidies will be encouraged; and
- one state's policy choices could contribute to a 'crowding out' of other competitive resources and resulting policy choices on which other states rely.

As the U.S. Supreme Court recently recognized, states rightly may pursue “various . . . measures . . . to encourage development of new or clean generation” or other vital public policy goals.¹⁰ Thus, the question raised by PJM's filing in this case is not *whether* states have the right to act but instead *how* the wholesale market should *respond* to such actions so that the goal of ensuring just and reasonable rates is not frustrated by an individual state's actions. To be clear, this filing does not seek any action by the Commission in preempting any state from making whatever policy choices it wishes. Rather, consistent with *Hughes* and the District Court's decision in *Village of Old Mill*

¹⁰ *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1299 (2016).

Creek v. Star,¹¹ the sole issue is how PJM and the Commission can ensure that the market can address these actions by states in a manner that does not undermine the fundamental purpose of the wholesale market.¹²

This is not a new issue for the Commission. The Commission has recognized the importance of this emerging issue, last year bringing together the three RTOs with competition-based capacity constructs, relevant states, and stakeholders for an in-depth discussion on potential conflicts between state resource policies and wholesale capacity markets.¹³ Further, PJM posted a detailed analysis to help initiate a discussion on this issue nearly two years ago, and along with its stakeholders toiled over this issue for a year, developing a range of responsive proposals. While that stakeholder process did not reach a consensus, that extensive process, along with the Commission's Technical Conference, provide a solid foundation for the constructive path forward PJM offers in this section 205 filing.

Specifically, by this filing, PJM:

- Demonstrates the time has come to fill a gap in the PJM Tariff, which currently has no way to address the adverse impacts of certain state subsidies on the PJM capacity market's ability to promote robust supply competition and send appropriate price signals;

¹¹ 2017 U.S. Dist. LEXIS 109368 (N.D. Ill. 2017).

¹² 2017 U.S. Dist. LEXIS 109368, at *43-44 (N.D. Ill. 2017) ("The market distortion caused by subsidizing nuclear power can be addressed by FERC. . . . So long as FERC can address any problem the ZEC program creates with respect to just and reasonable wholesale rates . . . there is no conflict.").

¹³ *See State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Notice of Technical Conference, Docket No. AD17-11-000 (Mar. 3, 2017) ("Notice of Technical Conference"); Transcript of Technical Conference, *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000 (May 1, 2017) ("AD17-11 Tr.").

- Offers a sequenced approach for the Commission to consider two alternate (mutually exclusive) proposals for ensuring PJM’s wholesale capacity market can maintain just and reasonable price signals notwithstanding the potentially significant distorting effect of state subsidies. Those alternatives, each containing all necessary tariff revisions, are:
 - Option A: Accommodate state subsidies in a way that avoids impacts on wholesale prices by repricing a subsidized offer after it has cleared at its subsidized level, so that all offers that clear are paid a competitive price (“Capacity Repricing”) or,
 - Option B: Mitigate the impacts of state subsidies on wholesale prices by repricing subsidized offers through extension of the Minimum Offer Price Rule (“MOPR-Ex”);
- Requests that the Commission accept the “Option A” tariff changes that PJM, consistent with the Commission’s tariff filing guidelines,¹⁴ designates as its preferred approach; and
- Requests that if the Commission cannot accept the accommodative Capacity Repricing approach, even subject to suspension and further proceedings, that it then accept the MOPR-Ex mitigation approach which this filing demonstrates is a just and reasonable alternative.

PJM proposes an effective date of January 4, 2019, for the accompanying Tariff revisions, and for that purpose requests waiver of the Commission’s 120-day maximum notice rule.¹⁵ However, PJM also asks the Commission to issue an Order on this filing by June 29, 2018. To that end, PJM has assigned an effective date of June 30, 2018, to a

¹⁴ See Office of the Secretary, *Implementation Guide for Electronic Filing of Parts 35, 154, 284, 300, and 341 Tariff Filings*, Federal Energy Regulatory Commission, 8 (Nov. 14, 2016), <https://www.ferc.gov/docs-filing/etariff/implementation-guide.pdf> (“FERC eTariff Implementation Guide”) (stating that public utilities may “propose alternate sets of Tariff Records (Option Sets) in a single Tariff Filing, with a request that FERC determine which Option Set to accept (i.e., place into effect). . . . For Tariff Filings with multiple Option Sets, the Tariff Submitter should make Option “A” its primary proposal.”).

¹⁵ See 18 C.F.R. § 35.3(a)(1). Waiver is warranted here, given that PJM proposes that these revisions will have their first application to the May 2019 Base Residual Auction. Given this filing’s significance, PJM is filing it well before that auction.

revised tariff record in each Option A and Option B.¹⁶ Based on PJM’s showings in this filing, the Commission has substantial evidence on which it could fully accept either of the two alternatives in an order issued by June 29, 2018. However, if the Commission determines, under the sequenced approach outlined above, that it can only accept one of the two alternatives subject to suspension and further proceedings, then PJM further requests that:

- The Commission accept and suspend only one of the two mutually exclusive alternatives, based on its required assessments under FPA section 205 guided by the Commission’s policy objectives;¹⁷
- The Commission not adopt trial-type proceedings, which are not needed or appropriate for a policy/market design question like that presented here;
- The Commission instead identify the subset of issues for which it seeks an additional record and order a paper hearing on those issues;
- In addition to the paper hearing procedures, the Commission provide the option for the parties to use settlement judge procedures to address the identified issues. Based on its extensive work with stakeholders on this topic, PJM anticipates that if the Commission makes the outstanding issues more manageable by accepting one of the two tariff alternatives, a good faith consensual effort could be the most productive means of resolving those outstanding issues; and

¹⁶ Specifically, PJM has assigned an effective date of June 30, 2018, to the Attachment DD title tariff record. No substantive changes are being made to this section.

¹⁷ As detailed in section III.B.2 below, this approach is grounded in Commission precedent. *See e.g., Midcontinent Indep. Sys. Operator, Inc.*, 157 FERC ¶ 61,242, at P 22 (2016) (“The [Commission-accepted alternative] approach . . . strikes a fair balance between reducing the burden of demonstrating and verifying facility-specific reference levels, and allowing a market participant to select the default technology-specific avoidable costs that best reflect its actual avoidable costs.”); *ISO New England Inc.*, 155 FERC ¶ 61,136, at P 27 (2016) (stating that the Commission-accepted tariff alternative “will lower the monthly amount charged as of the effective date, as compared to the one-year amortization of ‘Option A,’ and thereby minimize the immediate impact on transmission customers while the issues are being resolved at hearing”).

- The Commission issue its final decision on this filing by January 4, 2019, to allow PJM and market participants sufficient time to implement the accepted terms in time for the May 2019 Base Residual Auction (“BRA”) for the 2022/2023 Delivery Year—the first auction to which these rules are proposed to apply.

I. SUMMARY

In the CASPR Order, the Commission identified several “first principles of capacity markets,” i.e., that capacity markets like those of ISO New England and PJM should:

- facilitate robust competition for capacity supply obligations,
- provide price signals that guide the orderly entry and exit of capacity resources,
- result in the selection of the least-cost set of resources that possess the attributes sought by the markets,
- provide price transparency,
- shift risk as appropriate from customers to private capital, and
- mitigate market power.¹⁸

The performance of PJM’s capacity market plainly show these principles in action. Indeed, as shown below, PJM’s capacity market has been notably effective at:

- managing the orderly entry and exit of resources;
- Shifting risk from customers to private capital; and
- Shifting risk from customers to private capital.

In PJM parlance, “Generation Owner” describes entities that own power plants and sell to PJM Settlement, or those who sell to PJM Settlement on behalf of power plant owners, the energy, capacity and ancillary services provided by the power plant. Approximately 75% of the total PJM fleet is merchant generation. The financial and

¹⁸ CASPR Order at P 21.

operational risks associated with this generation are not imposed on consumers.¹⁹ And the owners of this generation depend on revenues from PJM's various markets to support their investment. The rest of the generation in PJM is owned by traditionally regulated, vertically integrated public utilities or public power.²⁰

For many years from the inception of PJM's markets in 1997, "Generation Owner" largely (but not exclusively) referred to publicly traded merchants, either independent power producers ("IPPs") or the functionally unbundled merchant affiliates of a publicly traded utility. In the last ten years, a new type of Generation Owner has emerged in large number to compete aggressively with incumbent merchant affiliates and IPPs. These merchants are private concerns, not capitalized in part by public equity markets, but by private equity and through structured and project finance vehicles.

As noted above, through PJM's capacity auctions held from 2010 through 2017, 50,792 MW of new generation capacity has been added, and 39,640 MW of generation

¹⁹ As PJM elaborated in its May 5, 2016 whitepaper, *Resource Investment in Competitive Markets*, PJM Interconnection, L.L.C., 13-14 (May 5, 2016), <http://www.pjm.com/~media/library/reports-notice/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx> ("*Resource Investment Whitepaper*");

[A regulated] return should account for the fact that investment risks are largely allocated to ratepayers in regulated environments. This situation stands in marked contrast to merchant investment in PJM where the market provides varying and uncertain revenues and return on the equity investment in a new generating asset. Additionally, the return realized by merchant investors must account for the costs they assume in wearing or managing all risks arising from developing and operating the asset.

²⁰ This discussion focuses on generation not only because it remains the vast majority of PJM Capacity Resources, but also to highlight the change in the generation sector from regulated to merchant. Demand Resources and Energy Efficiency Resources are important elements of the capacity resource mix, but their history as a significant resource coincides with (rather than pre-dating) the development of PJM's competitive markets.

capacity has retired or been derated.²¹ Over 32,000 MW of that new generation has been new highly efficient combined cycle gas-fired plants, along with approximately 7,000 MW of gas-fired combustion turbine plants.²² By PJM’s estimation, conservatively 70% of this new entry came from merchants, with the remainder brought in by vertically regulated or public power utilities.²³ Within this class of merchant entry over the last ten years, the overwhelming preponderance has been funded by private equity.

PJM’s recent capacity market auctions have seen tens of thousands of megawatts of new combined cycle gas enter in the face of historically low wholesale energy prices, flat to declining load growth,²⁴ increased transmission investment and reduced congestion

²¹ 2020/2021 RPM BRA Report at 19.

²² *Id.* at 21 (Table 8), 22 (Figure 4). *See also Resource Investment Whitepaper* at 13-14; AD17-11 at 240:24-25, 241:1-3, 250:21-23, 272: 10-16 (“We have some of our coal plants next to combined cycle plants that we run by gas sometime to 35 cents per million BTU and there is nothing that can compete with that. And those [coal] plants end up, you know, retiring.”).

²³ As explained in the *Resource Investment Whitepaper* (at 23), “evidence shows that PJM has successfully attracted significant new merchant investment in generating plants,” including “[p]ublic information available on financings established to support investment in PJM in the last several years suggest[ing] that banks and other lenders have evolved innovative structures particularly responsive to PJM’s capacity and energy market designs,” with the result that “[d]ebt and equity capital is being attracted to these structures, which are successfully closing and leading to new merchant combined-cycle investment.” PJM cited “ten leading examples of these merchant structured financings.” *Id.* Analyses by the IMM further shows that the overwhelming majority of this investment is merchant in character. *See New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019*, Monitoring Analytics (May 4, 2016), http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf.

²⁴ *PJM Load Forecast Report*, PJM Resource Adequacy Planning Department, 3 (Jan. 2018), <http://www.pjm.com/-/media/library/reports-notice/load-forecast/2018-load-forecast-report.ashx?la=en> (“Compared to the 2017 Load Report, the 2018 PJM RTO summer peak forecast shows the following changes for three years of interest: The next delivery year – 2018-1,843 MW (-1.2%); The

rents, and very robust reserve margins, over 23% from capacity commitments in the most recent Base Residual Auction.²⁵ From the perspective of traditional utility planning, this new entry is not “needed” by an administrative determination of target capacity.²⁶ Its entry, rather, is explained by risk-bearing market participants’ expectations that:

- natural gas prices will remain low;
- the combined cycle technology characterizing most of this new entry will prove more efficient than certain incumbent, older coal, nuclear and natural plants; and
- innovative project financing structures involving the plant developer, equipment manufacturers, construction firms, and access to global pools of equity and debt can be employed to lower the overall cost of capital.²⁷

The strategy motivating this investment and entry into the PJM market is a *market expectation* that new entry can outcompete and displace older, less efficient incumbent resources. This kind of investment illustrates precisely how markets unleash competitive forces for the benefit of the consumer. This kind of investment is central to a long history of Commission policy embracing competition in wholesale electricity

next RPM auction year – 2021 -1,021 MW (-0.7%) The next RTEP study year – 2023 -90 MW (-0.1%)”); *see also* the U.S. Energy Information Administration’s recent report that, “[a]s electricity demand growth slowed, new capacity additions also slowed. In recent years, new capacity additions often compete with existing generators.” *Demand Trends, Prices, and Policies Drive Recent Electric Generation Capacity Additions*, U.S. Energy Information Administration (Mar. 18, 2016), <https://www.eia.gov/todayinenergy/detail.php?id=25432>.

²⁵ 2020/2021 BRA Report at 1.

²⁶ Because it is not “needed” in traditional utility terms, its impact is described as forcing a “premature” retirement of legacy assets. Here “premature” is measured in terms of the asset’s operational life, book life or the duration of its permits, but not its economically useful life.

²⁷ *See, e.g., Resource Investment Whitepaper* at 24-25 (discussing risk-management tools for merchant generation project developers, including “[s]tructured financing models that have evolved to facilitate capital formation specific to PJM’s markets.”).

markets.²⁸ This kind of investment is critical to enabling RPM to meet the Commission’s “first principle” of relying on price signals to manage the orderly entry and exit of resources.²⁹ In short, this is precisely the kind of investment and private capital risk-taking that just and reasonable wholesale market rules should enable, if not encourage. As the Commission explained in its CASPR Order, the ultimate goal of capacity markets “is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates.”³⁰

The merchant generation business in PJM has been hyper-competitive. Risks that were traditionally borne by customers have been shifted to investors with mixed results for those investors. For example, virtually every major publicly traded IPP (as distinct from utility affiliated merchants), over the last 10-15 years, has restructured its balance sheet through Chapter 11 reorganizations.³¹ Merchants have also faced consolidations,

²⁸ *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 1991–1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036, at 31,644 (1996) (stating a “goal of the Energy Policy Act [of 1992] was to promote greater competition in bulk power markets”), *order on reh’g*, Order No. 888-A, 1996–2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh’g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh’g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff’d in part & remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff’d sub nom. New York v. FERC*, 535 U.S. 1 (2002); Order No. 888 at 31,673 (The overriding purpose of the Commission’s efforts to require open access to the transmission system and encourage development of wholesale power markets, including the organized, regional markets administered by ISOs and RTOs, has been pursuit of Congress’s “goals of creating more competitive bulk power markets and lower rates for consumers.”).

²⁹ CASPR Order at P 21.

³⁰ *Id.*

³¹ NRG, Calpine, Reliant, Mirant, GenOn, and Dynegy present high profile examples of IPP Chapter 11 filings. The filing approximately a week ago by First

and/or acquisitions, and at least in the cases of PPL Corporation/Talen Energy Corporation and Calpine Corporation, transformation into privately held organizations.³² The competitive pressure arising from privately held investment in new combined cycle plants has taken its toll on IPPs and now has many utility-affiliated merchants struggling to maintain their existence.

For the last several years, the publicly traded parents of these merchants have been very clear to their Wall Street investors they are exiting or shrinking their merchant businesses. Some of these legacy assets have been purchased by private equity.³³ But for other legacy assets, despite the billions of dollars of private equity earmarked for investment in the sector, there do not appear to be buyers, at least not at prices acceptable to the utility-affiliated sellers.³⁴

Energy Solutions marked the first filing by a merchant affiliated with a PJM transmission owning utility.

³² See, e.g., Iris Dorian, *Riverstone Closes Take-Private Buyout of Talen Energy*, PE Hub Network (Dec. 6, 2016), [https://www.pehub.com/2016/12/3423728/; Calpine Agrees to be Acquired by Investor Consortium Led by Energy Capital Partners](https://www.pehub.com/2016/12/3423728/;Calpine%20Agrees%20to%20be%20Acquired%20by%20Investor%20Consortium%20Led%20by%20Energy%20Capital%20Partners), Business Wire (Aug. 18, 2017), <https://www.businesswire.com/news/home/20170818005196/en/Calpine-Agrees-Acquired-Investor-Consortium-Led-Energy>.

³³ See Peter Maloney, *Challenge for Merchant Generators Is Opportunity for Private Equity*, Utility Dive (Aug. 9, 2017), <https://www.utilitydive.com/news/challenge-for-merchant-generators-is-opportunity-for-private-equity/448899/>.

³⁴ See Linda Harris, *Mon Power, Potomac Edison Back Out of Pleasants Power Deal*, WVNews (Feb. 6, 2018), https://www.wvnews.com/news/wvnews/mon-power-potomac-edison-back-out-of-pleasants-power-deal/article_9904dcce-630d-59ef-9910-c5190f60bf15.html; see also *Demand Trends, Prices, and Policies Drive Recent Electric Generation Capacity Additions*, U.S. Energy Information Administration (Mar. 18, 2016), <https://www.eia.gov/todayinenergy/detail.php?id=25432> (“With increasing amounts of surplus generation, competitively determined capacity payments in regions that have instituted capacity auctions may be reduced. Operators of some

These assets are receiving a very clear signal from PJM's markets they should either retire,³⁵ or to the extent they have going-forward value, avail themselves of financial and commercial restructuring under protection of the bankruptcy law if necessary.

Instead, an emerging trend in PJM is for owners of these legacy assets to seek out-of-market support from states to forestall retirement and defeat the design objective of PJM's market, at the expense of their competitors and wholesale consumers.³⁶ PJM recognizes that a state may have strongly held policy reasons (e.g., social, political or environmental public policy) for providing out-of-market support to specific in-state resources or resource types. But regardless of the state's specific policy motivation, retaining or compelling the entry of resources that the market *does not* regard as economic, suppresses prices for resources the market *does* regard as economic. This in turn suppresses revenues for resources that depend on these prices to support their continued operation or their economic new entry. Eventually, unless these resources too are given a subsidy or (if they are essential to preserving reliability) a Reliability Must Run ("RMR") arrangement, they will be crowded out.³⁷

existing coal and nuclear power plants face growing challenges in covering their fixed costs.").

³⁵ AD17-11 Tr. at 284:13-16 ("[PSEG] are less than a month now from shutting down two of our plants in New Jersey about 1200 megawatts responding to exactly those same price signals."); Linda Harris, *FirstEnergy Will Deactivate Pleasants Power Station if No Buyer Is Found*, WVNews (Feb. 16, 2018), https://www.wvnews.com/news/wvnews/firstenergy-will-deactivate-pleasants-power-station-if-no-buyer-is/article_be513a39-27b5-55dc-b916-eaf1e99364ca.html; *see also* AD17-11 Tr. at 249:13-25.

³⁶ PJM describes these programs in section II.C below.

³⁷ The Commission "has previously found that it is not reasonable for buyer-side mitigation to depend on the intent of the seller because an artificially low offer

Finding the balance between the states' pursuit of their policy goals, and the need to preserve just and reasonable wholesale prices that support the level of investment needed to meet resource adequacy requirements is the point of this filing.

It can be tempting to believe that some “dabbling” to countermand market signals is tolerable. And indeed, as noted by the U.S. Supreme Court in this context, organized electricity markets cannot expect to be “hermetically sealed” from all manner of distortions that might make prices imperfectly competitive.³⁸ PJM’s filing recognizes that organized markets can and must continue to accept a tradeoff between perfect competition and interventions that affect price outcomes for the benefit of some at the expense of others. For this reason, both proposals advanced here respect and accept some degree of non-actionable subsidy. While each proposal draws the lines between actionable and un-actionable subsidy differently in places, both proposals recognize that programs which target large-scale, unit specific resources represent a serious escalation

price can unreasonably suppress market prices regardless of the seller’s intent.” *Midwest Indep. Transmission Sys. Operator*, 139 FERC ¶ 61,199, at P 69 (2012); *see also ISO New England, Inc.*, 135 FERC ¶ 61,029, at P 170 (2011) (“The Commission acknowledges the rights of states to pursue policy interests within their jurisdiction. Our concern, however, is where pursuit of these policy interests allows uneconomic entry of OOM capacity into the capacity market that is subject to our jurisdiction, with the effect of suppressing capacity prices in those markets. We note that our primary concern stems not from the state policies themselves, but from the accompanying price constructs that result in offers into the capacity market from these resources that are not reflective of their actual costs. We agree with arguments contending that OOM capacity suppresses prices regardless of intent and that the Commission has exclusive jurisdiction on assessing whether wholesale rates are just and reasonable. In fact, the Commission has previously found that uneconomic entry can produce unjust and unreasonable prices by artificially depressing capacity prices, and therefore, the deterrence of uneconomic entry falls within the Commission's jurisdiction. It is these unjust and unreasonable outcomes in a Commission-jurisdiction market that is the focus of our actions here.”).

³⁸ *FERC v. Elec. Power Supply Ass’n*, 136 S. Ct. 760, 776 (2016).

in the status quo and threaten the longstanding balance that has allowed PJM's markets to meet the Commission's "workably competitive" standard for organized wholesale electricity markets.³⁹

PJM's RPM rules have to date focused on the danger posed by below-cost, subsidized offers from gas-fired new entry plants on the assumption that below-cost offers from other resources are less likely to be as damaging because other resources have lower avoidable costs, or make up a smaller part of the resource base. As subsidies spread and grow however, those assumptions are no longer sufficient to ensure that RPM will continue to advance the "first principles" of capacity markets enunciated in the CASPR Order. For example, as detailed in this filing, a now-subsidized existing nuclear plant failed to clear the 2017 capacity auction, presumably because its costs of continued operation demanded more revenue than PJM's capacity market could provide. PJM's analysis, supported by the Affidavit of Mr. Adam J. Keech, Executive Director, Market Operations, shows that a subsidized zero-priced offer from that single plant would reduce capacity revenues for sellers of tens of thousands of megawatts of capacity in large portions of the PJM Region. Unsubsidized sellers in that plant's Locational Deliverability Area ("LDA") would see their capacity revenues reduced by an estimated 10%—due solely to the zero-priced offer from a single plant, under a single state subsidy program. As shown in this filing, supported by the Affidavit of Dr. Anthony Giacomoni, Senior Market Strategist, Emerging Markets accompanying this filing, similar state

³⁹ See, e.g., *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 53 (2005); Order No. 888 at 31,655 (stating that independent system operators "have the potential to provide significant benefits (e.g., to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power) and will further our goal of achieving a workably competitive market.").

subsidy programs are being proposed, and additional programs are already in place and growing.

The time has come, therefore, to fill this gap in the PJM Tariff, and ensure that the PJM capacity market can continue to support robust supply competition, set price signals to manage resource entry and exit, place risk on those compensated to provide capacity, and promote price transparency. After a lengthy PJM stakeholder process on this challenging issue, two alternatives emerged, but neither could gain the two-thirds affirmative sector vote needed for endorsement. Doing nothing, however, is not an option. As the RTO and public utility with tariff administration responsibilities over the capacity market rules⁴⁰ under FPA section 205, PJM is taking the action it has determined is needed to fill the PJM Tariff gap demonstrated in this filing. In executing PJM's responsibility to ensure reliability and robust competitive markets, PJM has assessed the need for these market rule changes, as supported by and set forth in the expert affidavits.

Both filed alternatives work to ensure that artificially low offers from subsidized resources will not suppress capacity market clearing prices. The two approaches differ, however, on the basic question of whether a subsidized resource's artificially low offer can be used to qualify it to receive a capacity commitment (as is the case with the Capacity Repricing proposal) or instead require such resources submit and clear a competitive offer in order to receive a capacity commitment (as is the case with the MOPR-Ex proposal). The PJM Board of Managers concluded that the choice between

⁴⁰ PJM recognizes that the MOPR-Ex proposal elicited substantially greater support in the stakeholder process than did PJM's Capacity Repricing proposal. Nonetheless, PJM must fulfill its independent tariff administration responsibilities as an RTO under FPA section 205, and does so here by presenting Capacity Repricing as the preferred "Option A" for the reasons set forth in this filing. *See* section III.C, *infra*.

these two approaches at its essence presents a federal policy question, i.e., should the PJM Region wholesale capacity markets accommodate state policy choices to promote and rely upon particular resources while still taking steps to maintain the integrity of the overall clearing price. If so, then Capacity Repricing provides a reasonable means to achieve that policy preference. Conversely, if the Commission's policy focuses more on mitigating the impact of state subsidies, then MOPR-Ex would ensure the market is protected from the suppressive effects of state-subsidized offers.

PJM has structured this FPA section 205 filing with Option A/Option B tariff revisions (and the proposed sequential consideration) to enable the Commission to decide that basic policy question in an order issued by the requested date of June 29, 2018. Each option includes all tariff revisions needed to implement Capacity Repricing, or MOPR-Ex, respectively, and this filing supports either one as a just and reasonable means to resolve the current omission in the Tariff.

II. COMMISSION ACTION IS NEEDED NOW TO FILL A GAP IN THE RULES FOR THE PJM CAPACITY MARKET, WHICH FACES A GROWING INCIDENCE OF RESOURCES RECEIVING OUT-OF-MARKET STATE REVENUES THAT COULD UNDERMINE THE MARKET'S ABILITY TO FULFILL THE COMMISSION-IDENTIFIED CAPACITY MARKET PRINCIPLES

A. The Commission Has Repeatedly Found It Just and Reasonable to Prevent Below-Cost Offers by Sellers Relying on Out-of-Market Revenue from Suppressing Capacity Prices

The U.S. Supreme Court has explained RPM “serves to identify need for new generation.”⁴¹ Specifically, “[a] high [RPM] clearing price . . . encourages new generators to enter the market, increasing supply and thereby lowering the [energy market] clearing price three years’ hence” while “a low clearing price discourages new

⁴¹ *Hughes*, 136 S. Ct. at 1293.

entry and encourages retirement of existing high cost generators.”⁴² Similarly, courts have held that markets like RPM are intended to “ensure both that existing generators are adequately compensated and that prices support new entry when additional capacity is needed.”⁴³

To achieve these objectives, a central premise of RPM is that sellers are expected to offer their capacity at a price sufficient to cover their costs, to the extent not recouped in other PJM markets. To that end, the Commission has held, “[a] competitive seller of capacity is expected to bid its going-forward costs, i.e., the fixed annual operating expenses that would not be incurred if a unit were not a capacity resource for a year.”⁴⁴

Conversely, RPM “will not be able to produce the needed investment to serve load and reliability if a subset of suppliers is allowed to bid noncompetitively.”⁴⁵ As the Commission has explained, “[m]arkets require appropriate price signals to alert investors when increased entry is needed.”⁴⁶ Consequently, submitting offers below the seller’s costs can “have the unintended effect of depressing the market clearing prices in [RTO] markets, thus adversely affecting other market participants.”⁴⁷

⁴² *Id.*

⁴³ *Me. Pub. Utils. Comm’n v. FERC*, 520 F.3d 464, 473 (D.C. Cir. 2008), *rev’d in part sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm’n*, 130 S. Ct. 693 (2010), *remanded*, *Me. Pub. Utils. Comm’n v. FERC*, 625 F.3d 754 (D.C. Cir. 2010); *see also N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,301, at P 63 (2008) (capacity markets are designed to “provid[e] proper market signals for new entry and existing capacity”).

⁴⁴ *PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,264, at P 56 (2008).

⁴⁵ *PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,157, at P 90 (2009).

⁴⁶ *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211, at P 103 (2008).

⁴⁷ *Cal. Indep. Sys. Operator Corp.*, 142 FERC ¶ 61,191, at P 28 (2013).

The Commission has been called upon before to address the potential adverse effects on the PJM capacity market from state sponsored resources. Citing “mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules,” the Commission ordered the elimination of a blanket exemption for state-sponsored new entry, finding that below-cost offers should not be allowed to suppress capacity prices below the levels needed to support competitive entry and preserve reliability.⁴⁸

The court of appeals in *NJBPU* upheld the Commission’s authority to protect the wholesale price from the adverse effects of subsidized offers, and accepted the Commission’s rationale for doing so.⁴⁹ The court relied on the Commission’s expressed concern that the “prospect of thousands of megawatts of new generation, developed under arrangements that would explicitly subsidize the resources regardless of Auction price, potentially being offered into the [PJM] [m]arket at a zero bid brought into focus the distortive effect . . . that the state exemption could have on market prices for all capacity.”⁵⁰ The court explained that:

[I]f the state[] wish[es] to use a new generation resource to satisfy [its] capacity obligations required under the [PJM wholesale capacity market], [then] the resource must clear the [PJM] [a]uction [and] if the state[’s] preferred generation resources fail to clear the auction . . . the states cannot use [those] resources to offset their capacity obligations in [the wholesale market].⁵¹

The court also observed that if the preferred resource does not clear the wholesale capacity auction and the state nevertheless compels its construction, then the state ““will

⁴⁸ See *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 139 (2011).

⁴⁹ *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 97-98 (3d Cir. 2014) (“*NJBPU*”).

⁵⁰ *Id.* at 100.

⁵¹ *Id.* at 97.

appropriately bear the cost of [those] decision[s],’ including possibly having to pay twice for capacity.”⁵²

The Commission reaffirmed these principles in the CASPR Order, explaining the ultimate goal “to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates” and affirming the Commission’s “duty under the FPA to take actions necessary to assure just and reasonable rates,” in cases where “participation of resources receiving out-of-market state revenues undermines those principles.”⁵³

B. The Fully Restructured States in the PJM Region Elected to Rely on Competitive Markets as the Means to Select Resources Needed to Serve Loads

Many states in the current PJM Region chose, approximately twenty years ago, to restructure electric service in their states and introduce greater reliance on competition. Rather than relying on an administratively dictated integrated resource plan, such states rely on the PJM-operated interstate wholesale markets to manage resource entry and exit and meet resource adequacy objectives.

Illinois, for example, restructured the electric industry in its state in 1997 to introduce greater reliance on competition.⁵⁴ In the restructuring legislation, the Illinois General Assembly expressly considered the anticipated “[i]mproved efficiencies in the use of industry assets and personnel” gained by relying on the market—instead of

⁵² *Id.* (quoting *Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009)).

⁵³ CASPR Order at P 21.

⁵⁴ *See* Electric Service Customer Choice and Rate Relief Law of 1997, 220 Ill. Comp. Stat. 5/16-126 (LexisNexis, Lexis Advance through P.A. 100-581 of the 100th Legis. Sess.).

regulators.⁵⁵ By “substituting competitive market pricing for regulated pricing of electricity in the wholesale and retail markets” the restructured markets could “send[] . . . more efficient price signals to operators and builders of electricity generators and to users of electricity” and could “shift[] the focus of risk bearing for the use of existing generating assets and personnel [and constructing new generating assets] from captive users (where much of it has rested in the current system of economic regulation) onto shareholders of unregulated generating companies.”⁵⁶ The Illinois Commerce Commission (“ICC”) advised the legislature at that time that it “supports a swift transition to a competitive electric industry in which prices are decided by market forces, *not by government*.”⁵⁷ Notably, the legislators who voted to approve restructuring appreciated fully that: “[o]nce industry restructuring has progressed to the stage where distribution companies, generating companies and transmission companies are deemed separate business[es] and the FERC has deemed the wholesale market prices to be just and reasonable, the State will have no more voice in the price that generating companies charge for unbundled electricity than they do over the price that oil refineries charge for gasoline.”⁵⁸

⁵⁵ Nancy Brockway, Randle Smith, and Charles Stalon, *Principles Applicable to the Electric Industry Reform Legislation*, The Governor’s Advisory Committee for Electric Utility Regulatory Reform, 11 (Apr. 28, 1997), https://sites.hks.harvard.edu/hepg/Papers/2011/Old/Brockway_Principles_1997.pdf (“Principles”).

⁵⁶ *Id.*

⁵⁷ *Analysis of Electric Restructuring with Particular Emphasis on Senate Bill 55*, Illinois Commerce Commission, Executive Summary at ii (Aug. 15, 1997) (emphasis added).

⁵⁸ Principles at 18; *see also* Request for Rehearing of the Illinois Commerce Commission, Docket No. ER13-535-002, at 11 (May 28, 2013) (“ICC Rehearing Request”). The ICC explains that Illinois is “a retail access state with no ICC

Maryland similarly restructured the electric industry in its state in 1999, introducing greater reliance on competition.⁵⁹ The Maryland Public Service Commission (“MdPSC”) has explained that “[t]he premise of the 1999 Act was that electric consumers would benefit more from a competitive market for their electricity rather than being captive to a single utility that had a monopoly on their electricity service.”⁶⁰

New Jersey likewise restructured its electric industry in 1997,⁶¹ with one of its stated purposes to “[p]lace greater reliance on competitive markets, where such markets exist, to deliver energy services to consumers in greater variety and at lower cost than traditional, bundled public utility service.”⁶²

Similarly, Ohio adopted its version of competitive electric restructuring with the passage of Senate Bill 3 in 1999.⁶³ This legislation allowed retail customers of Ohio’s investor-owned electric utilities to shop for alternative suppliers of the generation portion of their electricity service.⁶⁴

jurisdiction over generation facilities in Illinois,” ICC Rehearing Request at 11, as distinct from “traditionally regulated states,” *id.* at 10, in which “the[] legislature or state commission could direct a state-jurisdictional utility to place [a preferred generation plant] into the state-approved integrated resource plan.” *Id.*

⁵⁹ See Electric Customer Choice and Competition Act of 1999, Md. Code Ann., Pub. Util. § 7-501, et seq.

⁶⁰ *In the Matter of Baltimore Gas and Electric Company’s Proposal*, Order No. 81423, at 36 (Md. Pub. Serv. Comm’n May 23, 2007).

⁶¹ See Electric Discount and Energy Competition Act, N.J. Stat. § 48:3-49 *et seq.* (LexisNexis, Lexis Advance through New Jersey 218th First Ann. Sess., L. 2018, c. 4 and J.R. 2).

⁶² N.J. Stat. § 48:3-50.

⁶³ 1999 Bill Text OH S.B. 3.

⁶⁴ Ohio Rev. Code Ann. 4928.02 (2012). The law was subsequently amended in 2008 pursuant to SB 221. 2007 Ohio S.B. 221 (enacted 2008).

A former FERC Commissioner has observed that states that embraced the restructuring model “effectively gave-up the type of resource adequacy planning authority that exists in . . . other [regulatory] models,” and therefore instead rely on “a separate FERC jurisdictional capacity market construct.”⁶⁵ However, the recent trend, as exemplified by the PJM Region experience described in this filing, is states that restructured are increasingly “seeking to procure vast amounts of megawatts of capacity around markets that were designed with the merchant generator model in mind.”⁶⁶ To that observer, state actions “have reached [a] tipping point”⁶⁷ and “[w]hile it can be alluring to think one can maintain all the benefits of a restructured market while also selecting your generation winners and losers . . . that is a siren’s call best left unanswered.”⁶⁸

C. There Is a Growing Trend Among the PJM Region States that Elected to Rely on Competition for Resource Adequacy to Intervene in Resource Selection with Targeted Subsidies

Increasingly, states in the PJM Region that chose to rely on competitive markets to ensure resource adequacy have adopted programs that provide substantial subsidies to resources that sell wholesale services in PJM’s markets. As detailed in the attached affidavits of Mr. Keech and Dr. Giacomoni, these programs are explicitly intended to encourage development or retention of select resources with certain attributes favored by state public policy. These programs, which directly or indirectly require payments from

⁶⁵ Tony Clark, *Regulation and Markets: Ideas for Solving the Identity Crisis*, Wilkinson, Barker, Knauer, 5 (July 14, 2017), [http://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20\(7-14-17\).pdf](http://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf).

⁶⁶ *Id.* at 13.

⁶⁷ *Id.*

⁶⁸ *Id.* at 15.

consumers⁶⁹ to those resources that offer the desired attributes, have now progressed to the point that thousands of megawatts of existing PJM Capacity Resources receive these subsidies. That growth is reasonably expected to continue. As Mr. Keech and Dr. Giacomoni also show, the dollar amount of these subsidies is significant; and reduced capacity price offers from resources that receive such subsidies can significantly reduce capacity clearing prices. As made clear in the review of Commission policy and precedent in section II.A above, such offer price reductions due to subsidies for select resources, as opposed to lower price offers based on resource efficiency, unreasonably suppress wholesale prices.

1. Overview of State Programs, Their Scope, and Their Subsidies

Dr. Giacomoni summarizes PJM Region state programs that provide subsidies of concern. He describes,⁷⁰ for example:

- Zero-emission credit (“ZEC”) payments to a select PJM Region nuclear plant in Illinois;
- Pending New Jersey legislation that would provide similar payments to potentially nuclear plants in that state;
- Off-shore wind procurement programs under existing law in Maryland and New Jersey that appear similar to the programs in New England that

⁶⁹ Although state consumers pay these support payments in rates in the first instance, as will be shown later in this filing, these payments can be offset by the suppressive impact they cause to clearing prices. In other words, these state programs can be structured in such a way that competitors in the wholesale market, already disadvantaged in not getting a subsidy, also end up footing some or all of the bill for subsidies enjoyed by others as a result of the lower revenues they receive. *See infra* II.C.3.

⁷⁰ Attachment F Affidavit of Dr. Anthony Giacomoni on Behalf of PJM Interconnection, L.L.C. ¶¶ 5-17 (“Giacomoni Aff.”).

prompted the ISO New England capacity market changes approved in the CASPR Order;⁷¹ and

- Renewable Portfolio Standard (“RPS”) programs in various PJM Region states that require Load Serving Entities (“LSEs”) to meet a certain percentage of their load with RPS eligible facilities, or buy renewable energy certificates (“RECs”) from such facilities.

Dr. Giacomoni also explains that these programs “are expressly designed to promote the development or retention of specific types of resources;” and “[a]vailable evidence indicates that they do indeed contribute to that objective.”⁷² He shows that some asset owners, specifically the owners of the nuclear plants in Illinois and New Jersey, make this linkage explicit, stating that their continued operation or capital maintenance of the plants is conditioned on securing the ZEC payments. Similarly, he cites an independent study showing that “mandatory RPS policies have been a ‘key driver’ for renewable energy generation growth; and that the RPS role has been ‘seemingly most critical’ in the states of the PJM Region.”⁷³

Dr. Giacomoni shows that the referenced state programs “provide subsidies to thousands of MWs of PJM Capacity Resources, and that number is scheduled to grow

⁷¹ See CASPR Order at dissenting op. 3 n.4 (Commissioner Powelson) (“‘An Act to Promote Energy Diversity’ was signed by the Governor of Massachusetts on August 8, 2016, and requires electric utilities in the state to procure 9.45 terawatt-hours per year from ‘clean energy generation’ and 1,600 MW of nameplate capacity from offshore wind.”); ISO New England, Inc. CASPR Filing at Geissler Testimony at 8 & Table III.1 (stating that the Massachusetts “2016 Energy Diversity Act” calls for utilities to procure “up to 1600 MW” of off-shore wind by 2025-2027).

⁷² Giacomoni Aff. ¶ 18.

⁷³ *Id.* ¶ 17 n.28 (citing Galen Barbose, *U.S. Renewables Portfolio Standards 2017 Annual Status Report*, Lawrence Berkeley National Laboratory, 12 (July 2017), <http://eta-publications.lbl.gov/sites/default/files/2017-annual-rps-summary-report.pdf> (“LBL 2017 RPS Status Report”)).

significantly under current law.”⁷⁴ Specifically, the Illinois ZEC program provides subsidies to approximately 1,400 MW of nuclear generation. If the similar New Jersey law is adopted, it would provide payments for up to 3,360 MW at the Salem and Hope Creek nuclear plants. The New Jersey offshore wind program contemplates supporting up to 1,100 MW of wind turbines; the Maryland program contemplates supporting a project of up to 250 MW. Dr. Giacomoni also estimates that satisfying the current RPS obligations in the PJM Region would require nearly 5,000 MW of “‘around-the-clock’ capacity (located and metered in the PJM Region),” and that is scheduled under current law to grow to over 8,000 MW by 2025.⁷⁵

In the last section of his affidavit, Dr. Giacomoni shows that “[t]he out-of-market financial support provided by the state programs at issue is substantial.”⁷⁶ To put this in perspective, he “compare[s] the subsidies to prices paid to resources that clear PJM’s capacity market,” recognizing that “[a] revenue source comparable to the PJM capacity market . . . is a significant revenue source, which could meaningfully affect whether or not a resource is economic.”⁷⁷ He finds that many of these the subsidy payment rates, when converted to MW-day values, in fact *exceed* capacity clearing prices in PJM’s most recent annual auction. The Illinois ZEC prices equate to about \$265/MW-day; New Jersey on-shore wind REC prices equate to \$250/MW-day; Delaware’s estimated on-shore REC prices equate to \$253/MW-day, and Solar REC prices in the District of Columbia equate to \$4,751/MW-day. While acknowledging that dependence on these

⁷⁴ *Id.* ¶ 24.

⁷⁵ *Id.* ¶ 29.

⁷⁶ *Id.* ¶ 31.

⁷⁷ *Id.*

subsidies will vary by resource, Dr. Giacomoni observes that “at these subsidy levels,” it is “quite plausible to conclude that . . . many resources do depend on those revenues, in combination with PJM market revenues, to be economic.”⁷⁸

2. *Simulated Market Impacts of the State Programs*

In his affidavit, Mr. Keech shows that “[s]ubsidized, below-cost capacity offers can result in significant and widespread clearing price reductions that are attributable to the subsidies.”⁷⁹ Working with Base Residual Auction sensitivity analyses that illustrate the effects of adding 3,000 or 6,000 MW of supply in various areas, Mr. Keech finds that “adding comparatively small quantities of subsidized offers disproportionately reduces the clearing prices paid to all resources.”⁸⁰ Adding less than 2% of zero-priced supply to the area outside MAAC, for example, reduces clearing prices in the RTO by 10%. Adding only 7% of zero-priced supply (i.e., about 2,000 MW) to EMAAC reduces EMAAC clearing prices by about one-third.⁸¹

Mr. Keech also simulates the clearing-price effects of offering at zero price the capacity from the Quad Cities and Three Mile Island nuclear plants.⁸² He shows that “[a]llowing just these two plants to offer into the capacity auction at a subsidized price of zero would reduce the capacity revenues received *by every seller in the unconstrained portion of the RTO* by 2%.” While that 2% reduction does not sound very significant, it equates to a reduction of \$547,500 for a resource seller with a 1,000 MW resource, for

⁷⁸ *Id.*

⁷⁹ Attachment E Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C. ¶ 6 (“Keech Aff.”).

⁸⁰ *Id.* ¶ 7; *see also id.* at Attachment 1.

⁸¹ *Id.* ¶ 8; *see also id.* at Attachment 1.

⁸² *Id.* ¶ 10; *see also id.* at Attachment 2.

example.⁸³ Sellers in the ComEd LDA would see their capacity revenues “cut by nearly 10% due solely to allowing the subsidized offer,” resulting in “a reduction in annual capacity market revenues of \$6.75 million for that same 1,000 MW UCAP resource.”⁸⁴

3. *The Effects of State Subsidies to Sellers that Offer into PJM Markets Are Not Confined to the State; They Significantly and Adversely Affect Wholesale Market Participants*

The wide-ranging price effects of the subsidy in the simulation above, e.g., reducing the clearing price paid to sellers throughout the unconstrained part of the RTO, hint at a critical insight about the respective role and responsibilities of state and federal regulators where these subsidies are concerned. Simply put, a state’s subsidies to wholesale market participants impose costs on market participants and customers outside such state’s purview that participate in, or depend on, the wholesale markets. In effect, the state is exporting the impact of its subsidy onto other states and potentially ‘crowding out’ resources that other states (with different policy choices) may value.

The following simple example illustrates these points.⁸⁵ It assumes a system with 200 MWs of load and three resources, each with 100 MWs of capacity, seeking to be committed in the PJM auction to serve that load. One resource is a new entry plant that needs \$45/MW-day to warrant investing in and building the plant. One is an existing

⁸³ *Id.* ¶ 10.

⁸⁴ *Id.* ¶ 11.

⁸⁵ PJM acknowledges this example is simplified with only a few resources and a small amount of load, and omits some real world details, such as reserve margins. The example also assumes \$2 of subsidy will reduce the clearing price by \$1. The mathematics of this relationship will almost certainly differ in actual subsidy situations. However, as the simulations shown in Section II.C.2 above illustrate, due to the “leverage” that comes from lowering the clearing price across many thousand megawatts of load in a zone, the cost of a subsidy can be fully underwritten even if \$1 of subsidy for a 1,000 MW resource only reduces the clearing price across 20,000 MW zone by \$.05.

resource that needs at least \$40/MW-day to meet its avoided costs to support committing itself as capacity. And the third is another existing resource, albeit one that is more costly and needs at least \$50/MW-day to support committing itself as capacity.

As shown in Figure 1, with no state intervention, the existing resource needing \$40/MW-day and the new entry resource needing \$45/MW-day clear the market and are committed to meet the 200 MW capacity requirement of the loads. The existing resource that needs \$50/MW-day does not clear the auction, and retires. The clearing price is set at \$45/MW-day, and load pays \$9,000 per day in PJM’s market for the 200 MW of capacity.

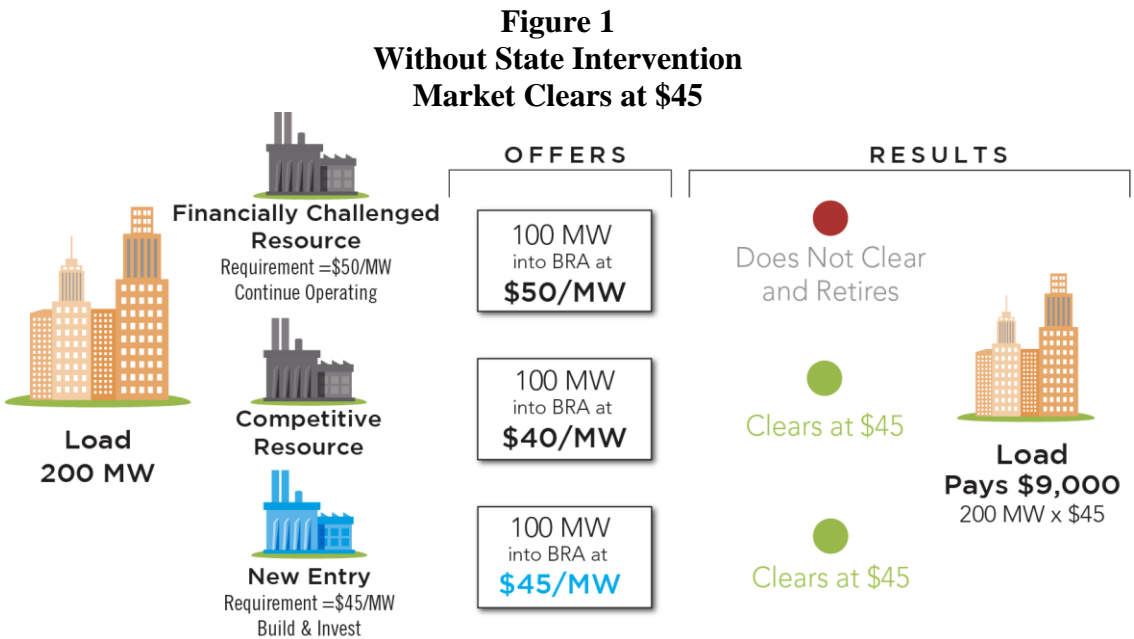
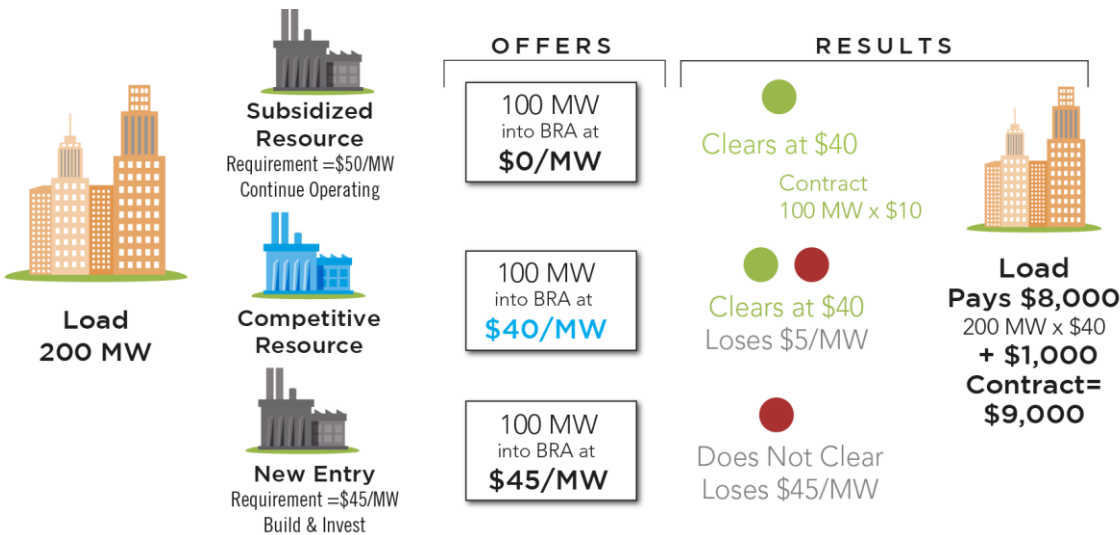


Figure 2 takes the same simple system, but introduces state action, with an arrangement for load to pay the difference between the \$50/MW-day the financially challenged existing resource needs from the capacity market, and the clearing price actually received from the capacity market. With the subsidy, the financially challenged existing resource is willing to take whatever price the capacity market pays, so it offers at

zero price. The subsidized resource clears, as does the existing resource that needs \$40/MW-day from the capacity market to cover its avoidable costs of providing capacity. The clearing price is \$40/MW-day, and the new entry resource that needs \$45/MW-day to invest and build does not clear.

Figure 2
With State Intervention (Contract for Differences)
Market Clears at \$40



Note that in this example, in-state load pays no more in total in the subsidy scenario than it paid in the non-subsidy scenario. Under the subsidy scenario, load still pays \$9,000/day for capacity, but now it consists of \$8,000 through the PJM market, and \$1,000 out-of-market to the financially challenged resource. Consequently, the state has realized its objective to keep the challenged resource in operation, but the costs of that decision do not fall on the state's loads. Rather, the immediate costs of keeping an uneconomic plant in service fall on the other sellers in the PJM market. In this example, the other existing resource foregoes the \$5/MW-day it would have received from being

an infra-marginal resource in a competitive auction. And the new entry plant forgoes the \$45/MW-day it would have received by being the marginal resource in a competitive auction.⁸⁶

Longer term, the state load potentially faces a more costly system, because efficient new entry was turned aside as a result of the subsidy. The state otherwise expects to rely on the competitive market to meet its load's long-term reliability needs at an efficient cost. But subsidizing one uneconomic plant is not enough to ensure long-term reliability, because the competitive mechanism (on which the state otherwise depends) has been thwarted. Other potential new entrants that need a market that values their capacity based only on their project's cost efficiencies may be deterred from offering into a market whose results are significantly affected by selective state subsidies.

The real world is more complicated than this simple example, but it serves to illustrate a critical point: the state subsidy program is being underwritten by other participants in the wholesale market. The question of state subsidy programs is not just a matter of respecting a state policy choice within its domain, it also imposes *important and detrimental consequences on the federally regulated wholesale market*. Advancing state policy by offering a subsidy tied to revenues received by a resource in PJM's markets effectively forces other participants in the wholesale market to pay for that objective. Therefore, this is not merely a case of discrimination between one party that enjoys a subsidy and one that does not. It is worse than that, because other wholesale

⁸⁶ These impacts on suppliers are relevant under the FPA, which requires rates that balance "the investor and the consumer interests," *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944), and "encourage the orderly development of plentiful supplies of electricity . . . at reasonable prices." *NAACP v. FPC*, 425 U.S. 662, 670 (1976).

market participants, excluded from the subsidy, are also effectively required *to help pay* for the favored party's subsidy. That forced enlistment of other wholesale market actors to help the state achieve its objective necessitates a response *by the federal regulator* of the wholesale market.

4. *A Part Subsidized/Part Competitive Market Cannot Carry Out the Critical Function of Ensuring Reliability*

If the clearing price reductions shown above resulted from real cost reductions or greater efficiencies, load would benefit because its reliability need would be met at lower cost. But the price reductions in the simulation result solely from the impacts of subsidies. As Mr. Keech explains in his affidavit:

Many sellers submit zero-price offers in PJM's capacity market. But this does not prove that many sellers are irrational. Sellers estimate whether they will recover their resource's costs in PJM's markets. If they anticipate that, for a given Delivery Year, they might not fully recover their resource costs in PJM's energy and ancillary service markets—and *they are not receiving a subsidy*—then they will offer into the capacity market at a price they consider the minimum needed to continue the operation of their resource through that Delivery Year.

* * *

By contrast, a zero-priced offer *that is made possible only because a seller receives an out-of-market subsidy* is not competitive behavior. The seller is relying on a state subsidy available only to select resources to submit an offer in the PJM capacity market that is well below what it needs if one looks only at its resource costs and the revenues available to it from PJM's other markets.⁸⁷

As a result, plants that demonstrably cannot clear based on their costs instead clear solely because of the subsidy and reduce the price paid to all other resources to meet the reliability needs of loads in the relevant area.

⁸⁷ Keech Aff. ¶¶ 14-15.

Loads that see capacity prices reduced from such subsidies are given incorrect price signals and a false promise. Basing clearing prices on costs that are distorted or biased by subsidies makes it harder for all other resources to clear based solely on their resource efficiencies or cost advantages. A market that does not fairly value the costs of meeting reliability needs will not continue to commit the resources needed for adequacy that compete only on their true net costs (allowing for wholesale market revenues), and not on those biased by subsidies. Thus, even if state policy makers choose to maintain their particular subsidy to their preferred resources, investment in needed resources in the region will become less sustainable over time, because otherwise efficient, but unsubsidized, resources are more likely to be priced out by the subsidized clearing price.

The suppressed price loads see also ignores that “subsidies beget subsidies:” basing markets on subsidies, rather than on costs, incents suppliers to seek subsidies of their own.⁸⁸ Subsidy-based markets are inherently risky and unstable, because each additional asset owner that seeks, and obtains, a subsidy disrupts the ability of more sellers to clear based on their cost efficiencies. A part-subsidized/part-competitive market is thus a very poor design choice for the critical function of ensuring reliability.

One could argue that subsidies of various types could affect behavior of many market participants. And it is true that markets, especially in the utility sector, include subsidies of varying types. The issue, however, is materiality. It is commonplace to refer

⁸⁸ See *Staff Report to the Secretary on Electricity Markets and Reliability*, U.S. Department of Energy, at 14 n.q (Aug. 17, 2017) (noting that “subsidies beget subsidies”); see also *State of the Market Report for PJM*, Monitoring Analytics, LLC, 42 (Mar. 8, 2018) http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-volume1.pdf (“Subsidies are contagious.”).

to wholesale electricity markets as “workably competitive,”⁸⁹ reflecting that many factors remove such markets from a competitive ideal. The record here, however, shows the emergence of multiple specific, substantial state subsidy programs that could have a material price suppression effect in the wholesale capacity market. In every prior case where the Commission has been faced with evidence of such growing threats to competitive wholesale markets, it has taken action.⁹⁰

D. PJM’s Tariff Currently Has No Means to Address the Adverse Effects of Any of the Above-Described State Subsidy Programs

PJM’s current Minimum Offer Price Rule applies only to new entry by gas-fired combined cycle and combustion turbine generating plants.⁹¹ It does not apply to resources after they have cleared one RPM auction. Nor does it apply to coal-fired, nuclear-powered, or renewable generation resources, or to demand resources.

Consequently, the PJM Tariff currently has no means to address the price-suppressing effects that might result from any of the existing or proposed state subsidy programs described above, despite the facts, as shown above and in the accompanying affidavits, that:

- The programs provide for out-of-market payments to resources that offer into PJM markets;
- There is ample evidence that the payments either are needed to keep the subsidized resources in operation, or at a minimum play a substantial role in keeping the resources in operation;
- The payments are substantial, in many cases exceeding PJM capacity market payments; and

⁸⁹ See *supra* n.39.

⁹⁰ See *supra* section II.A. See also CASPR Order at P 1.

⁹¹ See PJM Tariff, Attachment DD §5.14(h)(1).

- The number of megawatts of capacity receiving such payments is large and growing.

Accordingly, changes therefore are needed to remedy what is becoming an increasingly glaring omission from the PJM Tariff. By this filing, PJM provides two alternative proposals, each of which would remedy this omission.

E. Now is the Time for Commission Action

As the foregoing review makes clear, Commission action is needed now. The circumstances are similar to those that confronted the Commission in 2011 when it eliminated the blanket MOPR exemption for state-supported new entry: the “prospect of thousands of megawatts of . . . generation, [offered] under arrangements that would explicitly subsidize the resources regardless of Auction price, potentially being offered into the [PJM] [m]arket at a zero bid [brings] into focus the distortive effect . . . that the state [programs] could have on market prices for all capacity.”⁹² The principle applies equally here; the only difference is that in 2011, the concern was new entry, natural gas projects; today the concern arises from state programs to maintain and support existing resources and (to a lesser degree) induce entry of alternate energy resources. In such circumstances, where “participation of resources receiving out-of-market state revenues undermines [the first] principles” of capacity markets, the Commission has a “duty under the FPA to take actions necessary to assure just and reasonable rates.”⁹³

Some may argue that no action is needed at this time because capacity commitments in PJM are well above the installed reserve margin, and because the PJM Region continues to see new entry. This argument ignores the current drivers of new

⁹² *NJBPU* at 100.

⁹³ *CASPR Order* at P 21.

entry in PJM (see discussion of private equity models and gas turbine efficiency above, section I); and falsely suggests that there are times during the business cycle when it is appropriate to distort markets.⁹⁴

Moreover, being long on capacity does not justify setting subsidized clearing prices. A properly designed competitive market will address excess or shortage positions over time through the actions of competitive market participants. Excesses are not addressed by departing from competitive design principles (such as by allowing subsidies a significant role in setting clearing prices) until a surplus clears, and then trying to re-institute a competitive market design. The selected design must work in equilibrium, shortage, and surplus conditions. Subsidies will undermine competitive market design at any stage of the business cycle.

F. PJM, with its Stakeholders, Has Been Analyzing and Developing a Response to this Problem for Nearly Two Years

PJM has focused for nearly two years on the challenges increasing state subsidies present for competitive wholesale markets. In June 2016, PJM completed and posted an in-depth Whitepaper exploring whether PJM can continue to rely on the “organized wholesale electricity market to efficiently and reliably manage the entry and exit of supply resources as external forces create tremendous uncertainty and potential industry transformation.”⁹⁵

⁹⁴ Because electric demand growth in the PJM Region has been relatively flat for a number of years, the driver of new entry is not organic load growth or to add to the supply stack. Rather, as shown above, the investment hypothesis supporting new entry in PJM has been lower gas prices and better technology (i.e., technology that is more efficient and still innovating) to displace older less efficient generation. *See* further discussion in section I, *supra*.

⁹⁵ *Resource Investment Whitepaper* at i.

The *Resource Investment Whitepaper* concluded that “PJM markets are efficiently and reliably managing entry and exit, even while adapting to changing circumstances.”⁹⁶ The whitepaper noted that the PJM markets do well at attracting new entry at efficient cost because competition lowers cost and excludes technologies with inappropriately high costs. The Whitepaper also offered strong evidence that markets are providing adequate returns that incentivize new generation investment where needed.⁹⁷ The *Resource Investment Whitepaper* found no evidence suggesting that PJM markets do not adequately compensate legacy units such that economically viable generators were being forced into premature retirement.⁹⁸ Rather, the *Resource Investment Whitepaper* concluded, the PJM markets are producing prices that appropriately signal the exit of uneconomic legacy resources and the entry of efficient new resources.⁹⁹

Yet the *Resource Investment Whitepaper* also recognized that policymakers face difficult choices between the efficient market outcomes of the PJM markets and other policy objectives that may be thwarted by these outcomes. It further acknowledges the widespread subsidies that influence the PJM market outcomes and that PJM’s continuing ability to deploy market forces to efficiently and reliably handle a changing resource mix may be threatened if the promotion of other policy interests are pursued in a way that materially distorts price outcomes in PJM’s capacity and energy markets.¹⁰⁰

⁹⁶ *Id.* at i.

⁹⁷ *Id.* at ii.

⁹⁸ *Id.*

⁹⁹ *Id.*

¹⁰⁰ *Id.* at ii-iii.

The *Resource Investment Whitepaper* prompted stakeholder reaction, including through several letters sent to PJM to which Andrew L. Ott, PJM Chief Executive Officer, responded.¹⁰¹ To advance this and related topics, PJM conducted a “Grid 20/20” conference on August 18, 2016, to facilitate discussion about the confluence of market design and public policy goals and to explore with industry experts and regulatory officials various pathways in which market rules can accommodate policy goals without distorting market principles.¹⁰²

The Commission likewise recognized the challenges posed by this emerging issue, convening a technical conference on “an open question of how the competitive wholesale markets, particularly in states or regions that restructured their retail electricity service, can select resources of interest to state policy makers while preserving the benefits of regional markets and economic resource selection.”¹⁰³ The Commission then invited parties to file comments on “paths forward with respect to the interplay between state policy goals and the wholesale markets,” including Path 2 – Accommodation of State Actions and Path 5 – Expanded Minimum Offer Price Rule.¹⁰⁴

¹⁰¹ *Letter from Andrew L. Ott to Stakeholders*, PJM Interconnection, L.L.C. (July 8, 2016), <http://www.pjm.com/~media/about-pjm/who-we-are/public-disclosures/20160708-correspondence-from-alo-resource-investment-in-competitive-markets.ashx>.

¹⁰² *See Grid 20/20: Focus on Public Policy Goals and Market Efficiency*, PJM Interconnection, L.L.C., <http://www.pjm.com/committees-and-groups/stakeholder-meetings/symposiums-forums/grid-2020-public-policy-goals-mkt-efficiency.aspx> (last visited Apr. 4, 2018).

¹⁰³ *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Notice of Technical Conference, Docket No. AD17-11-000, at 1 (Mar. 3, 2017).

¹⁰⁴ Notice Inviting Post-Technical Conference Comments, Docket No. AD17-11-000, at 1-2 (May 23, 2017). *State Policies and Wholesale Markets Operated by ISO*

To further address these issues, the PJM Markets and Reliability Committee (“MRC”) created the Capacity Construct/Public Policy Senior Task Force (“Task Force”) “to conduct an assessment of the Reliability Pricing Model (RPM) in an effort to ensure potential state public policy initiatives and RPM objectives are not at odds.”¹⁰⁵ Specifically, the Task Force was asked to “identify both the characteristics of a well-functioning capacity construct, as well as potential public policy initiatives states could take regarding resource adequacy, fuel diversity, public, and environmental policies” and to “discuss whether modifications are required to RPM.”¹⁰⁶ The Task Force met twenty-two times between March 6, 2017 and November 21, 2017.¹⁰⁷ During this time, the Task Force considered both proposals being filed herein as well as six others. In November 2017, the Task Force voted on the various proposals and the IMM’s MOPR-Ex proposal received simple majority support. The Task Force presented the IMM proposal for a “first read” to the MRC¹⁰⁸ at the December 7, 2017 MRC meeting.¹⁰⁹ The MRC again reviewed the IMM proposal and related revised Tariff sheets at its December 21, 2017

New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.

¹⁰⁵ See *Capacity Construct/Public Policy Senior Task Force*, PJM Interconnection, L.L.C., <http://www.pjm.com/committees-and-groups/task-forces/ccpstf.aspx> (last visited Apr. 4, 2018).

¹⁰⁶ *Id.*

¹⁰⁷ *Id.*

¹⁰⁸ See *CCPPSTF Vote Results*, PJM Interconnection, L.L.C., 2 (Nov. 21, 2017), <http://www.pjm.com/-/media/committees-groups/task-forces/ccpstf/20171121/20171121-ccpstf-vote-results.ashx>.

¹⁰⁹ See *Markets and Reliability Committee, Agenda*, PJM Interconnection, L.L.C., 3, (Dec. 7, 2017), <http://www.pjm.com/-/media/committees-groups/committees/mrc/20171221/20171221-item-01-draft-minutes-mrc-20171207.ashx> (Agenda item 11).

meeting. The MRC deferred voting on the proposal until its next meeting on January 25, 2018, to provide stakeholders more time to review the revised Tariff sheets.¹¹⁰

At the January 25, 2018 MRC meeting, the IMM provided an update with regard to the MOPR-Ex proposal and associated Tariff revisions.¹¹¹ In addition, at the request of stakeholders, PJM management discussed PJM's updated proposal to accommodate state policy choices by addressing Capacity Repricing. The MRC voted on both proposals, neither of which passed. The IMM-proposed MOPR-Ex Tariff revisions failed in a sector-weighted vote with 3.19 in favor.¹¹² The PJM proposal failed in a sector-weighted vote with 1.07 in favor.¹¹³

In February 2018, the PJM Board of Managers, in response to "growing pressure threatening competitive outcomes in PJM markets," directed PJM to file both the MOPR-Ex proposal and the Capacity Repricing proposal with the Commission under section 205 of the FPA.¹¹⁴ As Mr. Ott explained in a letter announcing this decision:

Each approach represents a distinct, just and reasonable policy alternative to address the consequences of state intervention. Deciding between these policy options requires a balancing of federal and state interests, raising

¹¹⁰ See Markets and Reliability Committee, *Minutes*, PJM Interconnection, L.L.C., 2-3, (Dec. 21, 2017), <http://www.pjm.com/-/media/committees-groups/committees/mrc/20180125/20180125-item-01-draft-20171221-mrc-meeting-minutes.ashx> (Agenda item 7).

¹¹¹ Markets and Reliability Committee, *Minutes*, PJM Interconnection, L.L.C., 2 (Jan. 25, 2018), <http://www.pjm.com/-/media/committees-groups/committees/mrc/20180222/20180222-item-01-draft-minutes-mrc-20180125.ashx> (Agenda item 5).

¹¹² *Id.*

¹¹³ *Id.*

¹¹⁴ *Letter from Andrew L. Ott to Members and Stakeholders of PJM*, PJM Interconnection, L.L.C., 1 (Feb. 16, 2018), <http://www.pjm.com/~/-/media/about-pjm/who-we-are/public-disclosures/20180216-letter-from-pjm-president-and-ceo-on-behalf-of-the-board-of-managers-regarding-capacity-market-reforms.ashx>.

questions of federalism and comity that have already presented themselves before the courts, including the U.S. Supreme Court. Accordingly, the Board concluded that this question should fall to the Commission as the federal policymaker not to the PJM Board.¹¹⁵

In accordance with this direction, PJM submits this filing.

III. PJM PROPOSES TWO JUST AND REASONABLE APPROACHES—ONE PREFERRED, ONE ALTERNATE—TO ENSURE CONTINUATION OF A COMPETITIVE CAPACITY MARKET IN THE FACE OF THESE STATE SUBSIDY PROGRAMS

As the Commission, States, PJM, stakeholders, and other capacity market administrators have grappled with this issue over the past two years, two alternate paths have emerged for protecting wholesale capacity markets from the price suppressive effects of growing state subsidy programs: accommodate or mitigate. The choice between those two paths is easily defined, but not easily decided. The answer to a single question determines which path to take: Should the state-subsidized resource be given a real opportunity to be committed as capacity in the wholesale market notwithstanding its subsidized offer?

If the answer is *yes* (which is PJM's preference), then the path taken will likely entail two distinct auction steps—one to allow the subsidized resource a chance to be committed at its subsidized price, and one to set the clearing price based on competitive offers. On this path, the subsidized offer will be repriced to a competitive level *after* determining whether the subsidized resource offer clears the market. This path makes it much more likely that the subsidized resource will clear and receive a capacity commitment because it is first permitted to offer (and possibly clear) at a lower, subsidized level, rather than at its higher, competitive offer level. But PJM's Capacity

¹¹⁵ *Id.*

Repricing Proposal would not permit the subsidized offer to factor into formation of the clearing price and thereby suppress the clearing price. Instead, a second step in the auction process would replace the subsidized offer with a proxy offer designed to reflect what a competitive offer from that resource would have been. This repriced proxy offer, along with all offers from competitive sellers, would establish a clearing price for the auction.

If the answer to the above question is *no*, then the path taken will look something like the current MOPR, but expanded to apply to the additional subsidy programs of concern. On this path, the subsidized offer will be repriced to a competitive level *before* determining whether the offer clears the market. If the offer cannot clear at that price, then the resource is not committed. The resource that the state deems necessary to meet its public policy objectives will not be credited as capacity in the wholesale market, resulting in the relevant LSE having to procure its share of capacity through RPM at the RPM clearing price. If the resource can remain in service without PJM capacity market revenues, then loads bearing the cost of the subsidy will effectively pay twice for the same increment of capacity—once through the PJM capacity market, and once through the subsidy payments.

These two basic alternative paths were highlighted during the robust discussion at the Commission's May 2017 Technical Conference in Docket No. AD17-11 on capacity markets and state public policies. Participants adopted a short-hand reference

“accommodate” for the path that provides the subsidized resource a greater likelihood to clear;¹¹⁶ and the short-hand “mitigate” for the MOPR-style path.¹¹⁷

This choice also was a focus of the proceeding that led to the CASPR Order. ISO New England emphasized that the CASPR proposal provides an opportunity for states, over time, to get credit for their selected renewable resources in the ISO New England capacity market.¹¹⁸ Most notably, the multiple Commissioner opinions that accompanied the CASPR Order highlight the prime arguments in favor of the alternative paths. Commissioner LaFleur, for example, presents the practical rationale for some manner of

¹¹⁶ See, e.g., AD17-11 Tr. at 59:3-10 (LaFleur) (“I think we are at accommodate because . . . it would take a genius to back design the market to come up with this much off-shore wind and this much [of each other state-prescribed resource type] so should we be trying for that attribute or . . . should we just be trying to protect the price of everything else and let you run with your market?”); *id.* at 79:18-25 (Fuller, NRG) (“[State actions] are going to happen . . . So we need to accommodate them in the markets, recognize the double payment problem, the double purchase problem, figure out a way to allow those resources to actually have their role in the markets while not undermining the markets for those of us who have invested strictly on the basis of market revenues.”); *id.* at 100:19-23 (White, ISO New England) (“We agree that accommodating the current activities of the state[s] is a pressing issue for New England. I think that has been an increasingly prevalent view that I take away from our broader integrating markets and public policy process.”); *id.* at 241:21-25 (Ott, PJM) (“[PJM has] tried to address this proactively [and] put forth . . . a couple of different tracks of activity [but] [f]irst and foremost this issue of continuing to fight and have litigation is . . . not a great strategic plan.”).

¹¹⁷ See, e.g., Post-Technical Conference Comments of Dynegy Inc., Docket No. AD17-11-000, at 4 (June 22, 2017) (“Path 5’s robust buyer-side mitigation mechanisms”); Post-Conference Comments of the Electric Power Supply Association, Docket No. AD17-11-000, at 5 (June 22, 2017); AD17-11 Tr. at 201:3–9 (Patton, Potomac Economics). Although the Technical Conference also outlined other options based on “achieving” the state’s goal or simply keeping the status quo, witnesses at the Technical Conference and in post Technical Conference comments were not able to define how those options would be effectuated in a multi-state RTO when the state policies were potentially in conflict with one another.

¹¹⁸ CASPR Order at P 6.

accommodative approach given “the reality” that an increasing number of states are pursuing programs to support select resource types as part of their “clean energy policies.”¹¹⁹

By the same token, Commissioner Powelson’s dissent highlights the strongest argument for a MOPR-style approach, i.e., while “states are entitled to procure any resources they prefer,” no affected state “has signaled a desire to change current responsibilities for resource adequacy,” which “remain[s] within the purview of the regional grid operator,” and thus “it is the Commission’s responsibility to ensure that this objective is accomplished at just and reasonable rates.”¹²⁰ This divided vote on the CASPR Order highlights that the choice between these two paths is a policy decision.

PJM emphasizes that *either* Capacity Repricing *or* MOPR-Ex would be just and reasonable, because either would prevent state-subsidized capacity offers from suppressing prices in the capacity market. As shown above, PJM has no rules in place today to address subsidies to existing (as opposed to new) resources. Consequently, if, for example, an Illinois ZEC subsidy allows the Quad Cities nuclear plant to be offered into the PJM capacity auction at zero price, nothing in the current rules would prevent the type of price suppression—due solely to the subsidy—shown in the simulation described above.

That price suppression degrades the PJM Region’s ability to honor *each* of the “first principles of capacity markets” listed¹²¹ in the CASPR Order:

¹¹⁹ CASPR Order at concurring op. 2-3 (Commissioner LaFleur).

¹²⁰ CASPR Order at dissenting op. 2 (Commissioner Powelson).

¹²¹ CASPR Order at P 21.

- It undermines robust competition because other sellers cannot compete against a substantial subsidy available only to select capacity sellers;
- It distorts price signals needed to guide orderly entry and exit because the clearing price does not reflect the costs of the committed resources that, in reliance on the subsidy, offered well below their net costs of committing as capacity;
- It does not result in selecting least-cost resources that possess the attributes sought by the market, because those resources may be priced out by subsidized resources that are selected despite their higher costs;
- It undermines price transparency because the actual cost of providing capacity is not being transparently communicated since it is masked by the subsidy;
- It shifts risk *from* private capital *to* customers, because resource owners are insulated from the financial consequences of a resource that cannot, based on its economics, clear in a competitive auction, with customers (and other wholesale market participants as shown in Figure 2 above) bearing the costs of keeping the resource in operation; and
- It does not recognize or address any market power that may be involved in the submission of a below-cost offer.

These concerns are addressed, and the capacity market's ability to honor the "first principles" is restored, by adopting either Capacity Repricing or MOPR- Ex.

As explained in section III.B below, PJM prefers the Capacity Repricing proposal, and has designated it as Option A in this filing. Because the fundamentals of this approach result in respecting and accommodating state policy choices while ensuring the market signals a competitive price, PJM prefers this path and requests that the Commission assess first whether it can accept Option A, even if subject to suspension and further proceedings. However, if the Commission finds that it cannot accept the Capacity Repricing proposal, even subject to suspension and further process, PJM asks that the Commission consider and accept MOPR-Ex (Option B) proposal, which this filing demonstrates is a just and reasonable alternative means of addressing the identified problem. Consistent with how the Commission has previously handled such tariff

alternatives, and with the Commission’s eTariff rules,¹²² the alternative Tariff records PJM designates as Option A and Option B are mutually exclusive—only one can be accepted.

A. PJM Is Properly Exercising Its FPA Section 205 Rights to Submit Two Just and Reasonable Approaches—One Preferred, One Alternative

The FPA authorizes a public utility with a tariff filed with the Commission to change any rate, charge, classification, service, rule, regulation, or contract in such tariff by filing with the Commission “new schedules stating plainly the . . . changes to be made in the schedule . . . then in force and the time when the . . . changes will go into effect.”¹²³ Under FPA section 205 “the power to initiate rate changes rests with the utility.”¹²⁴ The Commission has no power “to force public utilities to file particular rates,”¹²⁵ or to “deny a utility the right to file changes in the first instance.”¹²⁶ Rather, the Commission “can . . . review [the filed] changes under section 205 and suspend them for a period of five

¹²² FERC’s eTariff program allows public utilities and regulated pipelines “to propose alternate sets of Tariff Records (Option Sets) in a single Tariff Filing, with a request that FERC determine which Option Set to accept (i.e., place into effect). . . . For Tariff Filings with multiple Option Sets, the Tariff Submitter should make Option “A” its primary proposal.” See FERC eTariff Implementation Guide at 8.

¹²³ See 16 U.S.C. § 824d(d).

¹²⁴ *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002).

¹²⁵ *Id.* (citing *Pub. Serv. Comm’n v. FERC*, 866 F.2d 487, 488-89 (D.C. Cir. 1989); *W. Res., Inc. v. FERC*, 9 F.3d 1568, 1578 (D.C. Cir. 1993); *Consumers Energy Co. v. FERC*, 226 F.3d 777, 780 (6th Cir. 2000); *Louisiana v. FPC*, 503 F.2d 844, 861 (5th Cir. 1974)).

¹²⁶ *Id.*

months, but it can reject them only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”¹²⁷

Public utilities have from time-to-time exercised their FPA section 205 rights by filing alternative versions of “new schedules stating plainly the . . . changes to be made”¹²⁸ that provide the same date by which both alternatives would go into effect, thus making the alternatives mutually exclusive.¹²⁹ Interstate gas pipelines have occasionally employed the same technique when filing tariff changes under the comparable provisions of section 4 of the Natural Gas Act (“NGA”).¹³⁰ The practice is sometimes used as a means of accommodating the outcome of the Commission’s decision on a related issue in a pending proceeding.¹³¹ In such instances, the utility (or pipeline) is using its filing rights to propose that the tariff change in the instant case should track whatever the Commission decides in the related case.

In other instances, the filing company asks the Commission to make a substantive choice in the newly initiated proceeding between two (or more) fully stated tariff change alternatives, stating plainly in its filing that the filing company considers either alternative a reasonable change to its tariff. Thus, for example, the Commission has

¹²⁷ *Id.* at 9 (quoting 16 U.S.C. § 824d(e)) (citing *City of Campbell v. FERC*, 770 F.2d 1180, 1184-85 (D.C. Cir. 1985); *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 952-53 (D.C. Cir. 1983)).

¹²⁸ 16 U.S.C. § 824d(d).

¹²⁹ *Id.*

¹³⁰ 15 U.S.C. § 717c.

¹³¹ *See, e.g., Pac. Gas & Elec. Co.*, Letter Order, Docket No. ER18-408-000 (Feb. 7, 2018); *Gulf S. Pipeline Co.*, 149 FERC ¶ 61,173 (2014); *Ariz. Pub. Serv. Co.*, Letter Order, Docket No. ER13-2470-001 (Jan. 17, 2014); *Kinetica Energy Express, LLC*, 144 FERC ¶ 61,159 (2013); *S. Cal. Edison Co.*, 141 FERC ¶ 61,268 (2012); *Pac. Gas & Elec. Co.*, Letter Order, Docket Nos. ER13-46-000, -001 (Nov. 30, 2012).

exercised its judgment in FPA section 205 or NGA section 4 cases to choose between:

- (i) alternative approaches to determining, for market power mitigation purposes, the avoidable cost of a resource offering into a capacity market administered by an RTO;¹³²
- (ii) alternative time periods for amortizing and recovering from ratepayers the costs of a merger transaction;¹³³
- (iii) three entirely different percentage rates (with differing calculation assumptions) for a pipeline's fuel adjustment charge on expansion facilities;¹³⁴ and
- (iv) whether to allocate a share of the costs of new facilities to customers under certain contracts that were shielded by a prior settlement from the costs of certain other facilities.¹³⁵

When confronted with alternative sets of tariff changes, the Commission can exercise its authority under FPA section 205 (or under NGA section 4) to reject one of the alternatives, and accept the other. As permitted by FPA section 205, the Commission can then accept and suspend the selected alternative, subject to refund and the outcome of a Commission "hearing" (which need not be a trial-type hearing) on the proposal.¹³⁶ The

¹³² See *Midcontinent Indep. Sys. Operator, Inc.*, 157 FERC ¶ 61,242, at P 22 (2016) ("The [Commission-accepted alternative] approach . . . strikes a fair balance between reducing the burden of demonstrating and verifying facility-specific reference levels, and allowing a market participant to select the default technology-specific avoidable costs that best reflect its actual avoidable costs.").

¹³³ See *ISO New England Inc.*, 155 FERC ¶ 61,136, at P 27 (2016) (the Commission-accepted tariff alternative "will lower the monthly amount charged as of the effective date, as compared to the one-year amortization of 'Option A,' and thereby minimize the immediate impact on transmission customers while the issues are being resolved at hearing").

¹³⁴ See *Trailblazer Pipeline Co.*, 136 FERC ¶ 61,007 (2011).

¹³⁵ See *El Paso Nat. Gas Co.*, 133 FERC ¶ 61,104 (2010).

¹³⁶ See, e.g., *ISO New England Inc.*, 155 FERC ¶ 61,136, at P 1 ("[W]e accept Eversource Service's proposed 'Option B' tariff revisions for filing, suspend them for a nominal period, . . . subject to refund, and establish hearing and settlement judge procedures."); *Midcontinent Indep. Sys. Operator, Inc.*, 157 FERC

Commission in the cited cases has exercised its authority by rejecting one alternative (as unjust and unreasonable) while still being able to accept but suspend the other alternative.

In some cases, two parties have FPA section 205 filing rights over the same tariff, and have by contract reserved the right to submit a combined filing with their differing changes to the same tariff provisions.¹³⁷ Inasmuch as such private parties cannot, by contract, add to or subtract from the Commission's FPA section 205 authority, the Commission's action in these cases underscores that it can choose between such alternatives within the ambit of its section 205 authority.

Thus, FPA section 205 permits PJM to submit, and the Commission to act upon, two mutually exclusive tariff proposals, as PJM has done here.

In section III.B below, PJM provides a high level overview of the Capacity Repricing and MOPR-Ex proposals, explains PJM's preference for Capacity Repricing, but explains how either approach would be just and reasonable. In section III.C, PJM provides a detailed description and justification of Capacity Repricing. And in section III.D, PJM provides a detailed description and justification of MOPR-Ex.

¶ 61,242, at P 1 (“[W]e accept MISO’s proposed Tariff sheets in Tabs C and D of its filing subject to condition, . . . and reject [its] proposed Tariff sheets in Tabs A and B.”); *Gulf S. Pipeline Co.*, 149 FERC ¶ 61,173, at P 1; *Trailblazer Pipeline Co.*, 136 FERC ¶ 61,007, at P 1; *El Paso Nat. Gas Co.*, 133 FERC ¶ 61,104, at P 1.

¹³⁷ See, e.g., *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014); *ISO New England Inc.*, 145 FERC ¶ 61,095 (2013); *ISO New England Inc.*, 143 FERC ¶ 61,065 (2013).

B. While PJM’s Proposed Sequencing Enables Orderly Commission Processing of this Filing Under FPA Section 205, Either Capacity Repricing or MOPR-Ex Would Be Just and Reasonable

1. Overview of Capacity Repricing and MOPR-Ex Proposals

As noted above, the key conceptual difference between Capacity Repricing and MOPR-Ex is that MOPR-Ex (similar to the current MOPR) resets a subsidized offer to a competitive price level *before* determining whether the offer clears the auction; whereas Capacity Repricing resets a subsidized offer to a competitive price level *after* the offer clears at its subsidized level in an initial commitment phase of the auction. Of course, this conceptual difference in auction mechanics has important consequences, affecting whether the state favored resource is committed as a PJM Capacity Resource, and whether loads in the state might effectively pay twice for capacity.

a. Capacity Repricing High-Level Summary

The Capacity Repricing proposal has the following features and characteristics:

- It replaces the existing MOPR;
- It applies to offers from both existing resources and new resources that receive a material subsidy and meet the actionable subsidy criteria;
- The first stage of the auction, using subsidized prices, determines resource commitment; the second stage, substituting competitive prices for subsidized prices, determines the clearing price for all resources committed in the first stage;
- The single clearing price, resulting from second stage, will be paid to all capacity resources and charged to all zonal load;
- Given that two-stage structure, a resource offering at a price above the first-stage clearing price will not be committed even if its offer is below the second-stage clearing price;
- Capacity Repricing relies on the higher of the avoidable cost rate (“ACR”) or the resource’s specific opportunity cost as the measure of a competitive price in most cases;

- Rather than readopt the self-supply exemption that was in place (but rarely used) from 2013 through 2017, offers by the sellers that meet the substance of the former “Self-Supply Entities” definition (as modified) will *not* be subject to repricing;
- It is fuel neutral;
- The state subsidy programs described in section II of this transmittal and in the affidavit of Dr. Giacomoni exemplify the types of subsidies to which Capacity Repricing applies;
- It applies to a subsidized resource *only* if the dollar value of the subsidy each year is at least 1% of the resource’s annual revenues from PJM’s markets;
- It applies to a generation resource *only* if the resource capacity is 20 MWs or greater; there is no minimum resource capacity value in the limited circumstance where Capacity Repricing applies to Demand Resources;
- It does not apply to a generation resource for which energy production is a byproduct or ancillary to its primary business function, such as combined heat and power and the burning of municipal solid waste; and
- It will *not* apply to any offer in the PJM Region until 5,000 MW of offers subject to repricing have been offered in the PJM Region, unless offers equal to at least 3.5% of the Reliability Requirement in an LDA have been submitted in that LDA, in which case offers will become subject to repricing in that LDA.

b. MOPR-Ex High-Level Summary

The MOPR-Ex proposal has the following features and characteristics:

- It expands and extends the existing MOPR;
- It applies to offers from both existing resources and new resources;
- It uses the greater of ACR or the resource’s specific opportunity cost as the exception to the MOPR Floor Price measure of a competitive Offer;
- It readopts the substance of the competitive entry exemption that was in place from 2013 through 2017;
- It readopts a self-supply exemption based on that in place from 2013 through 2017, but adopts a new categorical exemption for public power entities and employs relaxed tests for qualifying for the exemption;
- It excludes (grandfathers) existing renewable resources and offers defined exclusion for future renewable resources;

- While generally fuel neutral, it applies to renewable resources only in certain limited circumstances; and
- It does not apply to Demand Resources.

2. *The Commission May Accept Either Capacity Repricing or MOPR-Ex as Just and Reasonable*

Capacity Repricing is PJM's preferred approach because it accommodates state policy choices while protecting the capacity market from the ill effects of price suppression. To accommodate the state's policy choice to support that resource, Capacity Repricing commits the resource if it can clear at its subsidized level in the initial auction phase. Capacity Repricing then includes that committed resource, at its competitive net costs of providing capacity, in the supply stack used to determine the clearing price. The clearing price thus reflects a competitive clearing price that respects the cost of the resources committed to serve the region. In short, the Capacity Repricing proposal is more in line with the comity that is needed between state actions and the federal regulatory scheme going forward. It recognizes that additional state action is inevitable and does not invoke punitive consequences for states invoking their legislative prerogatives. At the same time the Capacity Repricing approach recognizes the importance to the federal regulatory scheme of a representative clearing price that meets the Commission's stated objectives for capacity markets as enunciated in the CASPR Order. For these reasons, PJM prefers the Capacity Repricing approach and submits it to the Commission as its preferred option with a request that the Commission find it just and reasonable on its own merits under an FPA section 205 analysis notwithstanding the existence of the MOPR-Ex Option B.

PJM views MOPR-Ex as its secondary just and reasonable alternate. It mitigates the harm state policy choices have in suppressing capacity market prices. It does so by

preventing the subsidized offer from being submitted at a price below a competitive offer price in the first place. Instead of the below-cost offer that was enabled by the subsidy, the offer (assuming in the first instance it is below the screening level of Net CONE times B and does not qualify for a categorical exemption), will (through ensuing interactions with PJM and the IMM) likely reset to a competitive level, represented by ACR or opportunity cost. The repriced offer then will clear, or not, based on the estimated net costs of committing the resource as capacity. If the resource clears, then the clearing price will be determined based on a supply stack that includes the offer from that resource. If the resource does not clear at that price, then the clearing price will accurately signal that competitive pricing will not support the particular resource.

By basing clearing prices on the competitive costs of the committed resources, both Capacity Repricing and MOPR-Ex remedy the price signaling and transparency deficiencies from the current Tariff's acceptance and reflection of the subsidized existing resources at their subsidized (below-cost) price.

There is an important difference between the two approaches that gets to the heart of the policy question before the Commission: Capacity Repricing honors the state's legitimate policy choice to promote resources with certain attributes not otherwise valued in the current wholesale market rules; MOPR-Ex does not. *If* the Commission decides as a matter of federal wholesale market policy to respect those state policy choices, then Capacity Repricing should be accepted.

The theoretical ideal market approach to that issue would be to unbundle the currently unvalued attributes and enable resources to compete to provide those attributes, for example, through a carbon emissions objective embedded in the wholesale market

clearing mechanism if the states were so inclined to pursue that objective. That *may* be possible if there were just one attribute uniformly valued by all states across the PJM Region. But that's not the case. And, even if it were, there are a daunting number of practical, legal, and political obstacles that lie between the market's current state and any such theoretical approach that may (or may not) arise in the future.

For present purposes, however, the Commission certainly has the authority and discretion to approve an approach like Capacity Repricing, which both respects the states' decisions to value one or more non-wholesale electricity market attributes (e.g., carbon free emissions, jobs, environmental concerns) while exercising its jurisdictional authority over wholesale markets in determining which resources are selected to provide capacity and that the rates, terms, and conditions of such service are just and reasonable and not unduly discriminatory or preferential.

3. *Additional Differences Between Capacity Repricing and MOPR-Ex Are Important to Note but Do Not Impede a Commission Finding that Either Proposal Is Just and Reasonable*

Capacity Repricing and MOPR-Ex also have other differences resulting from the difference in their basic approach. In PJM's view, these differences are important, but not disqualifying. On balance, either Capacity Repricing or MOPR-Ex is just and reasonable as either would be a substantial improvement over the status quo of ignoring substantial subsidies to only certain resources participating in the wholesale capacity market.

a. MOPR-Ex Will Likely Result in Some Resource Duplication, Capacity Repricing Will Not

MOPR-Ex almost certainly will result in some duplication of resources needed to serve loads.¹³⁸ That duplication is limited in today's MOPR, because of its narrow application to only certain gas-fired new entry resources. Consequently, existing resources selected by the state for their environmental attributes (for example) can qualify today as capacity by submitting below-cost, subsidized offers that are not addressed by the current MOPR.

Capacity Repricing avoids that duplication, because it allows state-selected resources to commit as capacity at their subsidized offer price, even though the ultimate clearing price is based on the resource's actual costs. MOPR-Ex, by contrast, has the potential impact of disqualifying state-subsidized resources (especially those which are financially distressed and therefore are resources the states feel they need to subsidize in the first place) from clearing as capacity, and will clear *other* resources to meet capacity needs. In many cases, loss of capacity revenues likely will not induce retirement of the subsidized resource, and loads will be paying for more resources than it needs. As shown in section II.B above, the subsidies at issue are often already higher than currently prevailing capacity clearing prices.

¹³⁸ Proponents of MOPR-Ex hope that it will work to dis-incent states from providing subsidies in the first instance. While there is a basis for this hope, valid state interests might still motivate states in promoting uneconomic resources even in the face of the cost consequences imposed by MOPR-Ex. This will lead to a punitive duplication of resources, which should be understood as over-procurement. While MOPR-Ex works to protect capacity market prices from the suppressive effects of artificial over supply, it does not address the suppressive impact of this added supply of energy and ancillary services in those markets.

b. MOPR-Ex's Resource Duplication Presents Concerns for the Energy Market; Capacity Repricing Avoids this Issue

Consequently, MOPR-Ex will procure competitively priced capacity along the demand curve to satisfy PJM's installed reserve margin. At the same time, consistent with the state's intent, the subsidized resources will likely remain in service and continue operating in the PJM Region as well, supported by the subsidy. MOPR-Ex, therefore, while addressing price suppression in the capacity market, could well have the effect of *enabling* price suppression in the wholesale energy and ancillary service markets. The underlying problem, admittedly, is the subsidized resource. But the triggering or enabling event is the commitment as capacity (through MOPR-Ex) of a substitute resource at the margin that would not have cleared otherwise, and thus would have been under pressure to retire. Enabling this resource duplication thus results in greater supply in the energy market than economic conditions would otherwise justify. This, in turn, will tend to suppress prices in the energy market, and make it incrementally harder for otherwise economic resources to compete in those markets.

c. Capacity Repricing Can Result in Resources Not Being Committed Even Though Their Offer Price Is Below the Second-Stage Clearing Price; MOPR-Ex Does Not Raise this Issue

For its part, Capacity Repricing inherently results in resources not being committed as capacity if their offer price is higher than the subsidy-influenced price in the first stage of the auction, even if that resource's offer is below the clearing price determined by the second stage of the auction. This sub-optimal clearing result is inherent in any approach that accommodates the commitment of the subsidized resource as capacity, because such below-cost, subsidized offers will logically raise some risk of displacing resources at the higher-cost end of the supply stack. But this possibility does

not outweigh the inherent advantages of repricing as a workable policy alternative, or prevent it from being found just and reasonable. To the contrary, protestors in the CASPR proceeding similarly argued that under ISO New England's proposal, the substitution auction could induce certain sub-optimal effects in the primary auction.¹³⁹ In that case, the Commission was satisfied that this was not likely to be a substantial problem, but urged ISO New England nonetheless to monitor the auctions for such effects.¹⁴⁰

Some stakeholders have raised a concern that this effect of repricing could distort participants' bidding behavior; for example, encouraging sellers to bid low so as to guarantee they clear in the face of a subsidized low-price offer.¹⁴¹ To the extent this posits that *unsubsidized* sellers would offer *below their own net costs*, so as to commit to provide PJM capacity for a full Delivery Year *at a loss*, such concerns are speculative, to say the least. It is worth noting, moreover, that in the current PJM capacity market, the high-cost, marginal sellers likely will be less efficient legacy units (with a limited future economic life), as opposed to the new entry units classically assumed to be at the margin.

¹³⁹ CASPR Order at P 57.

¹⁴⁰ *Id.* at P 72.

¹⁴¹ PJM understands some parties would prefer an approach that would pay the clearing price from stage one to a Capacity Resource with Actionable Subsidy that receives a commitment in stage one, rather than paying that resource the stage two repriced clearing price. Such approach could be seen as striking a balance between the accommodating benefit of Capacity Repricing with the concerns voiced by some that paying subsidized resources the higher stage two clearing price offers no check on resources seeking a subsidy.

In short, concerns over this aspect of Capacity Repricing should not deter the Commission from accepting the repricing proposal, if the Commission prefers an accommodate approach.¹⁴²

C. OPTION A: Capacity Repricing, an Accommodative Approach to State Decisions by Repricing Subsidized Resources *After* They Clear in a Base Residual Auction

As discussed, PJM's preferred approach is Capacity Repricing. Under this approach, PJM proposes to address the impacts of state resource decisions to by instituting a two-stage Base Residual Auction in which clearing resources and assigning capacity commitments is performed in the first stage and determining market clearing prices is performed in stage two. The two-stage approach will allow all Capacity Resources for which the seller receives, directly or indirectly, material support from any state governmental entity connected with that resource's clearing in a Base Residual Auction, which subsidy is determined to be actionable as explained below, to clear the auction based on their submitted (i.e., unmitigated) offers.¹⁴³ That is, in the first stage, PJM will not seek to mitigate offer prices that may be suppressed due to out-of-market subsidies as PJM had done in the past through the Minimum Offer Price Rule. In the second stage, PJM will re-run the auction using the same demand curve, and the same supply stack. In that supply stack, PJM will use the same Sell Offers considered in the

¹⁴² If the Commission were instead to accept but suspend the Capacity Repricing proposal, then parties with concerns about, or alternatives to, this aspect of repricing (including even those who suggest the solution is to pay subsidized resources the lower stage 1 price, rather than the higher stage 2 price) would have a forum to press their concerns and preferred solutions.

¹⁴³ PJM is proposing to define such material support as a "Material Subsidy." See proposed PJM Tariff § 1, Definitions L-M-N (Option A). Whether receiving such Material Subsidy results in the resource becoming a Capacity Resource with Actionable Subsidy, and thus being repriced, is discussed in section III.C.3 below.

first stage, but for those cleared resources that qualify as Capacity Resources with Actionable Subsidy (as explained in section III.C.3 below), PJM will reprice their offers to the Actionable Subsidy Reference Price. Each Actionable Subsidy Reference Price will be a competitive offer price that is determined for that resource in accordance with the provisions of the revised market rules.¹⁴⁴ The intersection of the demand curve and the reconstituted supply stack that uses Actionable Subsidy Reference Prices will determine the Capacity Market Clearing Price.

It is important to note that, under Capacity Repricing, PJM is not proposing any changes to the process for how it clears Capacity Resources or the optimization algorithm it employs to clear the Base Residual Auction and assign capacity commitments. Rather, PJM is proposing to add a second stage to the Base Residual Auction process that only determines Capacity Market Clearing Prices.

However, this accommodative approach will not apply until a material amount of Capacity Resources with Actionable Subsidy offer clears a Base Residual Auction across the entire PJM Region or within any modeled LDA, as discussed in section III.C.5 below.¹⁴⁵ In other words, Base Residual Auctions will continue to clear resources and determine clearing prices in the same manner as in the past, until the megawatt quantity of Capacity Resources with Actionable Subsidy reaches a level so as to have a materially suppressive impact on clearing prices. From that point on, the two-stage approach will be used to the extent any Capacity Resources with Actionable Subsidies clear in stage one.

¹⁴⁴ See *infra* section III.C.4.

¹⁴⁵ See proposed PJM Tariff, Attachment DD § 5.14(a) (Option A).

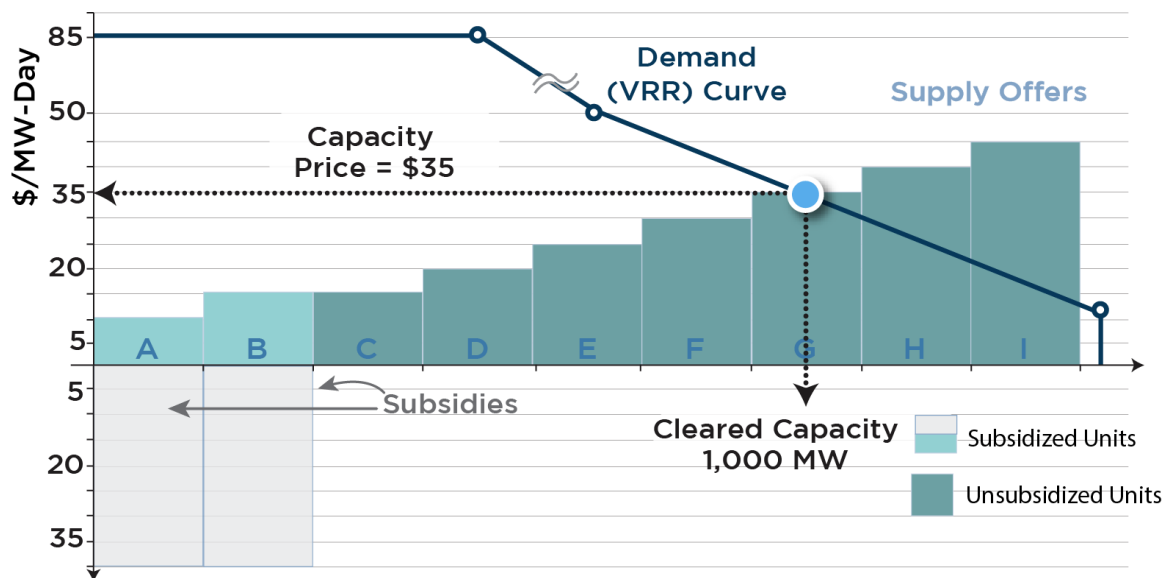
1. PJM Will Clear Resources First, Then Reprice Capacity Resources with Actionable Subsidies to Determine BRA Clearing Prices

As noted, under this approach, PJM will continue to clear Capacity Resources in Base Residual Auctions using the optimization algorithm that determines the least cost overall clearing results that satisfy the reliability requirements across the PJM Region and in each modeled LDA. In other words, “the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.”¹⁴⁶ In this way, PJM will continue to obtain the level of capacity commitments necessary to maintain reliability.

The optimization algorithm will consider the submitted offer price for each Capacity Resource, regardless of whether the resource’s seller is receiving out-of-market subsidies for such resource.¹⁴⁷ As a result, in the first stage of a Base Residual Auction, PJM would clear subsidized resources based on submitted sell offers, as shown in Figure 3 below.

¹⁴⁶ PJM Tariff, Attachment DD § 5.12(a).

¹⁴⁷ As explained in section III.C.7, PJM is proposing to eliminate the Minimum Offer Price Rule.

Figure 3**First Stage of Auction, Cleared Capacity Determined**

In Figure 3, the resources in columns A, B, C, D, E, F, and G cleared in the first stage and received capacity commitments. Columns A and B include subsidized resources, with the shaded portions below the x-axis reflecting the portions of the resource's going-forward costs that are subsidized and not reflected in their respective offer prices. Columns H and I do not clear, as their offers are above the \$35/MWh price at which the Variable Resource Requirement curve (i.e., the demand curve) intersects with the supply stack at column G. In other words, all resources would clear based on their submitted offers, and the optimization algorithm would run as usual, clearing all resources until the supply stack intersects with the demand curve.

Once the first stage is complete and the optimization algorithm has cleared sufficient Capacity Resources to meet applicable Reliability Requirements, PJM will then evaluate the Capacity Resources with Actionable Subsidies that cleared. If the first stage cleared 5,000 MWs or more of such resources (in unforced capacity terms) across the

entire PJM Region¹⁴⁸ or an amount equal to or greater than 3.5% of the Reliability Requirement for any modeled LDA,¹⁴⁹ then PJM will conduct the second stage of the proposed auction process and re-run the optimization algorithm to establish what the Capacity Market Clearing Prices would have been had the Capacity Resources with Actionable Subsidies cleared the auction based on competitive offer prices.

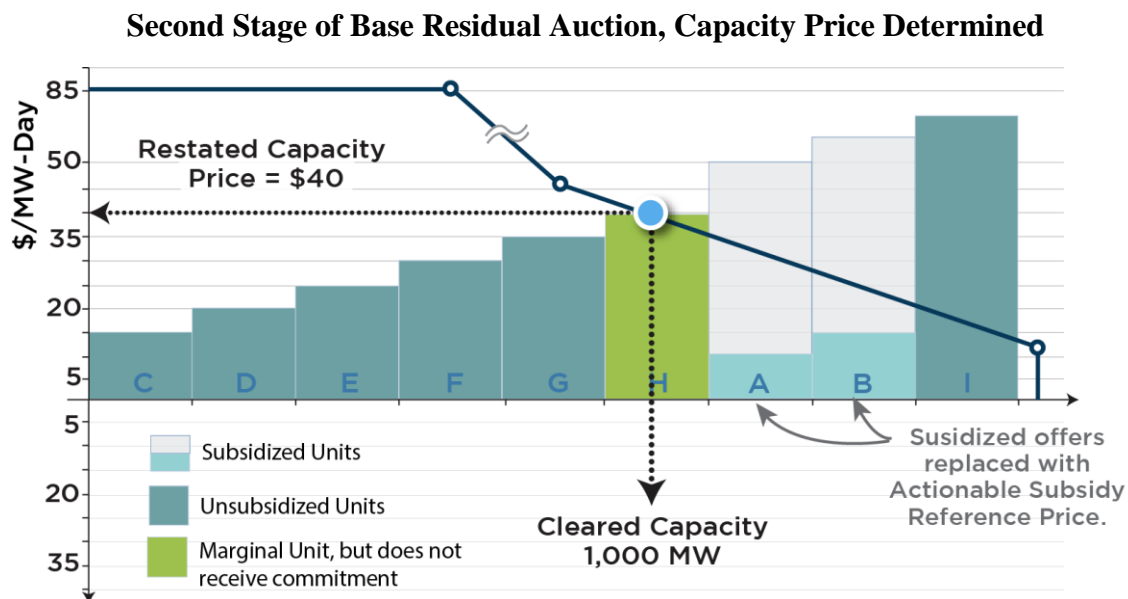
For each BRA after these material thresholds are first met, PJM will automatically run stage two and reprice any cleared Capacity Resources with Actionable Subsidies. The new offer price (i.e., the Actionable Subsidy Reference Price) will be a competitive offer price determined based on the facts and circumstances specific to each resource in accordance with the procedures set forth in the proposed market reforms,¹⁵⁰ which are explained in section III.C.4 below. Stated another way, PJM will replace the offers submitted by Capacity Market Sellers of Capacity Resources with Actionable Subsidies with offers reflecting what would be a competitive offer for such resource. While PJM will consider the same resources that comprised the supply stack in the first stage, no new capacity commitments will be made in the second stage. Rather, the second stage only establishes the Capacity Market Clearing Prices, but in all other ways respects the capacity commitments from the first stage.

Figure 4 illustrates how the second stage of the auction would re-run the optimization algorithm using repriced offers from Figure 3.

¹⁴⁸ See proposed PJM Tariff, Attachment DD § 5.14(j)(1)(a) (Option A). The reasoning for such materiality thresholds is explained in section III.C.5 below.

¹⁴⁹ See proposed PJM Tariff, Attachment DD § 5.14(j)(1)(b) (Option A).

¹⁵⁰ See proposed PJM Tariff, Attachment DD §§ 5.14(j)(1)(a)-(b) (Option A).

Figure 4

In Figure 4, columns C, D, E, F, and G represent resources that cleared in the first stage; columns H and I represent resources with offer prices too high to clear in the first stage; and columns A and B represent Capacity Resources with Actionable Subsidies that cleared in the first stage. Recall that columns A and B in Figure 3 represent Capacity Resources that cleared stage one based on their below-cost, subsidized offer prices. In Figure 4, the resources in columns A and B have been “repriced” with competitive offers for such resources and thus have been reshuffled in the supply stack. By shifting columns A and B to the right so as to place them in the supply stack at a point reflective of their new, repriced offers (at the Actionable Subsidy Reference Price), resources with lower offer prices are shifted to the left. Re-running the optimization algorithm with the reshuffled supply stack yields a different clearing price than in Figure 3. Thus, the clearing price, i.e., “the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located

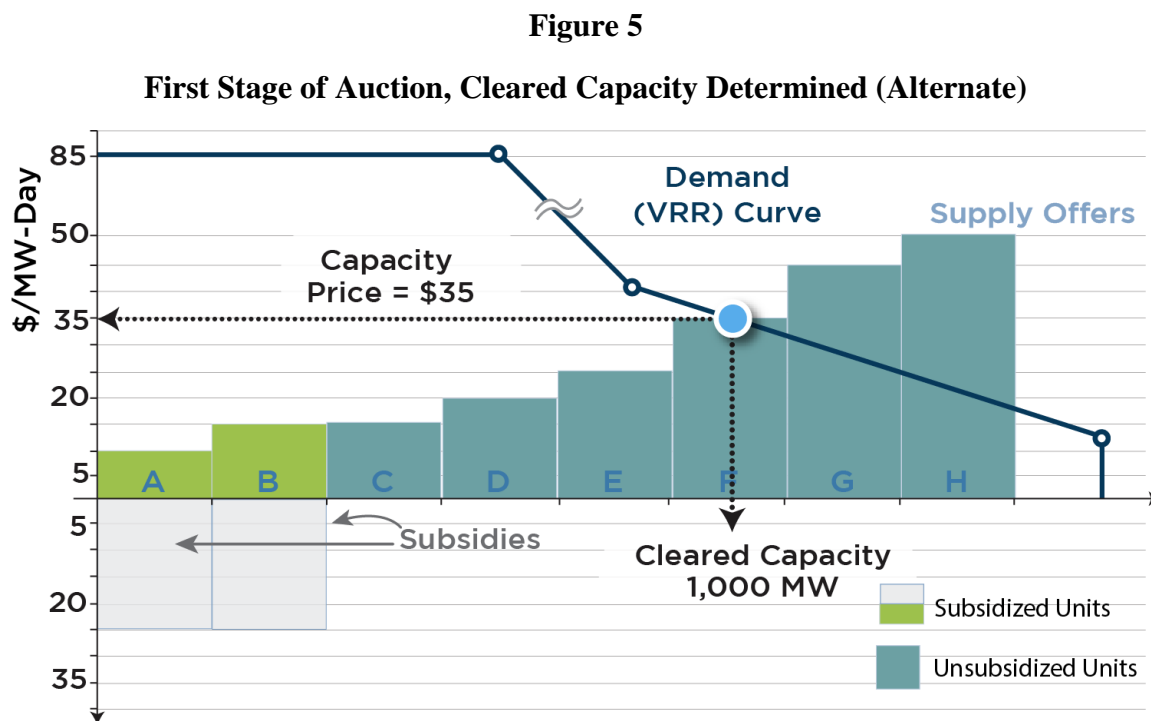
entirely below the Variable Resource Requirement Curve,”¹⁵¹ is now where column G intersects with the demand curve, i.e., \$40.

The \$40/MWh clearing price in Figure 4 is necessarily higher than the clearing price that would result from only the first stage in Figure 3 (i.e., \$35/MWh), given that the first stage cleared resources based on below-cost, subsidized offers that suppressed the clearing price. As a result, there will be resources that submitted offer prices below the clearing price established in the second stage that will not clear the Base Residual Auction and receive capacity commitment due to the point at which supply meets demand in the first stage. This is a logical outcome when the parameter of allowing all resources to clear based on their submitted offer prices is considered. Indeed, accommodating state resource decisions by allowing the auction to clear resources with below-cost, subsidized offers will unavoidably displace resources at the higher cost end of the supply stack.

Thus, the fact that the Capacity Market Clearing Price may be determined by a resource that did not clear the auction or receive a capacity commitment (see column H in Figure 4 above) does not undermine the validity of the BRA clearing results or the clearing price. Rather, it reflects the policy decision to accommodate state resource decisions and benefit load by allowing load to only pay for capacity once—through the capacity market, rather than paying once through the market and a second time through state payment to resources that did not clear the market.

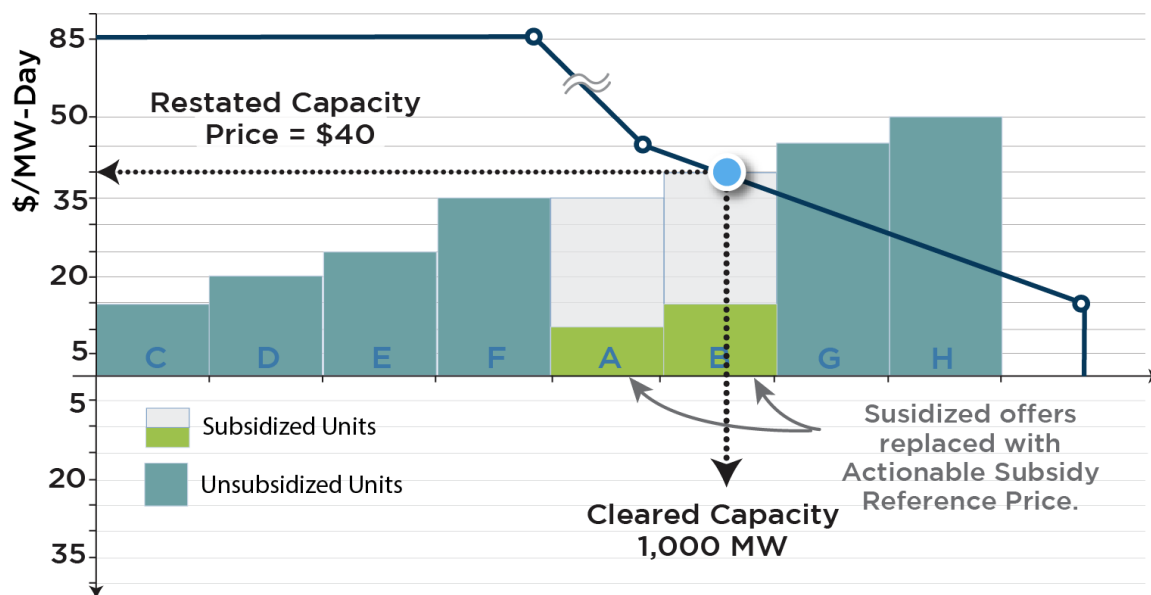
¹⁵¹ PJM Tariff, Attachment DD § 5.12(a).

However, the clearing price may not always be set by resources that do not clear in the first auction stage. Figures 5 and 6 below illustrate an alternative scenario in which a “repriced” resource offer sets the market clearing price.



As before, all resources clear based on their submitted offers. Columns A and B represent subsidized resources. As all resources clear based on their submitted offers, columns A through F clear in the first stage of the auction, and columns G and H do not clear and are not assigned capacity commitments.

For the second stage, shown in Figure 6 below, the resources in columns A and B are repriced to their Actionable Subsidy Reference Price, which will be the competitive offer price determined based on the facts and circumstances specific to each resource. Thus, to illustrate this repricing in Figure 6, the shaded portions of columns A and B that are below the x-axis are moved above the x-axis and added to the green portions of the columns. Then, the supply stack is reshuffled relative to the cost of each resource.

Figure 6**Second Stage of Base Residual Auction, Capacity Price Determined (Alternate)**

The result is that column B intersects the demand curve and sets the clearing price at \$40. Columns G and H, which represent resources that did not clear in the first stage, do not factor into the clearing price. Again, the \$40/MWh clearing price in the second stage (Figure 6) is necessarily higher than the clearing price that would result from only the first stage auction in Figure 5, given that the first stage cleared resources based on below-cost, subsidized offers that suppressed the clearing price. That is the point of this exercise—to determine auction clearing prices based only on competitive offers, while accommodating state policy decisions.

While the two scenarios presented in the Figures above are not exhaustive of all the possible outcomes, they illustrate how the auction process would work and how Capacity Resource Clearing Prices would be determined.

2. *Capacity Repricing Will Apply Only to BRAs*

PJM is proposing to apply Capacity Repricing's two-stage auction approach only to Base Residual Auctions, and therefore would not apply repricing in any Incremental Auction. There is no need to apply Capacity Repricing to Incremental Auctions as the concerns giving rise to Capacity Repricing—suppressed price signals—do not apply to Incremental Auctions, as they are not intended to be a mechanism that sends price signals regarding the need for entry and exit from PJM's capacity market. Thus, any suppressive impacts an out-of-market subsidy has on an offer price into an Incremental Auction would have no broader impact on the PJM Region warranting corrective action.

In addition, not employing a two-stage auction approach to Incremental Auctions is reasonable based on the difference in the entities that comprise supply and demand in the two auctions. The buyers in Incremental Auctions are capacity providers seeking to replace their capacity commitments, and they submit buy bids at specific offer prices at which they are willing to purchase replacement capacity. To clear an Incremental Auction based on those buy bids, and then run a second stage and determine a price *different from what the buyer offered* would result in the buyer being required to buy capacity at a price greater than it was willing to pay. This is unreasonable. On the seller side, the vast majority of resources offered are existing resources that failed to clear in the BRA for that Delivery Year. Such resources are not likely to be Capacity Resources with Actionable Subsidies (because, if they were, they could have submitted a subsidized offer that cleared in the BRA).

3. *Capacity Resource with Actionable Subsidy*

a. Qualifications for Being a Capacity Resource with Actionable Subsidy

To identify only those resources receiving a subsidy that warrants action based on design or market impact, PJM is proposing a narrow path for a resource to qualify as a Capacity Resource with Actionable Subsidy. As a rule, Capacity Resources are presumed to *not* be a Capacity Resource with Actionable Subsidy, unless certain criteria are met.

i. *The subsidy received must be material*

The first criterion is that the seller must in some way obtain a subsidy for the Capacity Resource. However, because not every subsidy impacts the seller's offer price to the same degree or even to a degree that materially suppresses the price, PJM is not lumping all subsidies together. Rather, PJM is proposing that only if the seller receives a "Material Subsidy" should the resource require further review to see if action is needed.

A Material Subsidy includes:

- material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or
- other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource.¹⁵²

PJM is including only those subsidies that would have a material impact on the seller's overall revenues from the subsidized resource.

¹⁵² See proposed PJM Tariff § 1, Definitions L-M-N (Option A).

Further, to make sure that only those subsidies that are material to the resource's capacity market impact are considered, PJM is also proposing to *exclude* certain types of local, state, and federal subsidies from consideration, such as:

- 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;
- 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
- 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.¹⁵³

Importantly, these exclusions are the same as those employed in the MOPR for several years prior to the Commission's removal of the Competitive Entry Exemption (without prejudice) in its order on the *NRG* remand. By defining both what types of subsidies to include and what types to exclude, the tariff-prescribed review will require only those resources in any way receiving subsidies with material impact to be considered further to determine if they are Capacity Resources with Actionable Subsidy and subject to repricing. Accordingly, the characteristics that qualify a resource as a Capacity Resources with Actionable Subsidy target only those resources likely to present legitimate price suppression concerns.

PJM's proposed definition of Material Subsidy properly focuses on subsidies that are "connected to the construction, development, operation, or clearing in any RPM

¹⁵³ See proposed PJM Tariff § 1, Definitions L-M-N (Option A). Any avoided cost payment received by Qualifying Facilities (as defined in Part 292 of the Commission's regulations) would *not* be a Material Subsidy. However, other forms of material support may qualify as a Material Subsidy.

Auction, of the Capacity Resource.”¹⁵⁴ This focus naturally targets state subsidies that provide material payments or other support and excludes federal subsidies. As a general matter, federal subsidies have broader application and more expansive scope than state subsidies, which are inherently geographically limited to the state boundaries. A primary issue with state subsidies is their discriminatory impact on the marketplace, by favoring certain resources over others. For example, during the technical conference in Docket No. AD17-11, concerns were raised about state government decisions that target specific resources.¹⁵⁵ PJM is excluding federal subsidies because it strains credibility to believe that the Commission’s jurisdiction under the FPA would extend to countermand other acts of Congress, including subsequent legislation addressing tax credits, such as the production tax credit (“PTC”) or nuclear plant liability limitations such as the Price-Anderson Nuclear Industries Indemnity Act.¹⁵⁶ Moreover from a policy point of view, these are generic actions with a nationwide scope. Investors and market participants also are more likely to have better understanding of and familiarity with acts of Congress, compared to individual state action focused on a particular unit or project.

PJM’s proposed definition of what comprises a Material Subsidy (and of which subsidies do not warrant concern) tracks directly the previously-accepted definition of

¹⁵⁴ Proposed PJM Tariff § 1, Definitions L-M-N (Option A).

¹⁵⁵ AD17-11 Tr. at 247:3–6 (“All of the generation in central and southern Illinois will vanish with the latest subsidy given to [Exelon, i.e., ZECs] and capacity clearing at 5 cents for KW month [in MISO], those plants were just put in the uneconomic category.”).

¹⁵⁶ See 42 U.S.C. § 2210.

subsidies for purposes of obtaining a Competitive Entry Exemption from the MOPR.¹⁵⁷

In evaluating the Competitive Entry Exemption, and its criteria, the Commission found it

reasonable for an RTO to propose tariff provisions to ensure that subsidized entry supported at the state level does not have the effect of disrupting the competitive price signals that PJM's wholesale capacity market protocols are designed to produce and on which PJM's market participants, region-wide, rely to attract sufficient capacity.¹⁵⁸

While the Commission rejected this exemption on remand from *NRG*, the Commission's reasoning for that rejection was limited to an evaluation of whether the categorical exemptions, standing alone, are just and reasonable, and not unduly discriminatory or preferential, without a unit-specific exception process.¹⁵⁹ Absent that concern, the Commission had otherwise found the details of the Competitive Entry Exemption to be reasonable. Thus, the Commission's subsequent rejection did not reach the merits of the Competitive Entry Exemption and was without prejudice.¹⁶⁰

ii. *Applicable resource types*

Because Material Subsidies can be granted broadly, PJM is proposing that Capacity Resources with Actionable Subsidies include: Demand Resources and Generation Capacity Resources—both existing and planned, and internal and external, or

¹⁵⁷ PJM Tariff, Attachment DD § 5.14(h)(7)(iii) (language in effect prior to Remand Order).

¹⁵⁸ *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 54 (2013) ("May 2013 Order"), *reh'g denied*, 153 FERC ¶ 61,066 (2015) ("October 2015 Order"), *vacated & remanded sub nom. NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017), *reh'g denied*, 2017 U.S. App LEXIS 18218 (D.C. Cir. Sept. 20, 2017) (per curiam).

¹⁵⁹ *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,252, at P 41 (2017) ("Remand Order").

¹⁶⁰ *Id.* at P 2 ("[The Commission's] determination is without prejudice to PJM submitting a new, revised FPA section 2015 filing if it determines doing so will cure the deficiencies with the December 2012 filing.").

an uprate of 20 MW or greater to a Generation Capacity Resource.¹⁶¹ The 20 MW threshold for Generation Capacity Resources (and uprates) is identical to the MOPR application threshold that the Commission previously accepted.¹⁶² PJM is excluding Energy Efficiency Resources from being able to qualify as a Capacity Resource with Actionable Subsidy because such resources are generally the result of a focus on reduced consumption and energy conservation¹⁶³ and do not raise price suppression concerns.

iii. *Criteria limiting Capacity Resource with Actionable Subsidy eligibility*

Given that the purpose of these market reforms is to address the price suppressive effects of material state subsidies on BRA clearing prices, PJM is proposing to exclude from the definition of Capacity Resource with Actionable Subsidy the types of resources that are not likely to raise price suppression concerns. To eliminate such resources from consideration, PJM is proposing to exclude from the definition of Capacity Resource with Actionable Subsidy those resources: (1) that obtain a non-material level of Material Subsidies (i.e., less than 1% of the resource's actual or anticipated PJM-market revenues);¹⁶⁴ (2) for which electricity production is not the primary business purpose, but rather is a byproduct of the business processes, or (3) that are owned or controlled by entities with long-standing business models for capacity procurement, which do not raise

¹⁶¹ See proposed PJM Tariff, Attachment DD § 5.14(j)(2)(b) (Option A).

¹⁶² May 2013 Order at P 170.

¹⁶³ For example, Energy Efficiency Resources are often founded on state programs that include rebates and incentives for behind-the-meter resources or programs that incent insulation, energy efficient buildings, etc.

¹⁶⁴ See proposed PJM Tariff, Attachment DD § 5.14(j)(2)(d) (Option A).

concerns of possible price suppressive intent (e.g., certain vertically integrated, cooperative, and municipal utilities¹⁶⁵).

Excluding Capacity Resources that receive a non-material level of Actionable Subsidies, i.e., less than 1% of the resource's actual or anticipated total revenues from PJM's energy, capacity, and ancillary services markets,¹⁶⁶ ensures that only a resource receiving a material amount of subsidies is considered to be a Capacity Resource with Actionable Subsidy. Thus, this threshold limits the impact of the Capacity Repricing approach to address only those resources that obtain subsidies to such a degree that the seller's offer price may be affected.

Excluding those generation resources for which energy production is a byproduct of a resource owner's primary economic interest in the facility is reasonable. Such resources would include those fueled entirely by, for example, landfill gas, wood waste, municipal solid waste, black liquor, coal mine gas, or distillate fuel oil. Energy production is a byproduct of these resources' primary economic purpose (e.g., managing waste). As such, the economics of energy production and energy market participation for these resources is much more complicated than for a typical Generation Capacity Resource. Thus, obtaining capacity market revenues is not necessarily critical to such resources, and they do not present the price suppression concerns that these market rules address.

Finally, excluding resources offered by certain vertically integrated, cooperative, and municipal utilities is similar to the Self-Supply Exemption the Commission had

¹⁶⁵ See proposed PJM Tariff, Attachment DD § 5.14(j)(2)(c) (Option A).

¹⁶⁶ See proposed PJM Tariff, Attachment DD § 5.14(j)(2)(d) (Option A).

previously accepted for application of the MOPR,¹⁶⁷ in that such exclusion appropriately balances between protecting against price suppression while avoiding interference with long-standing capacity procurement business models. Indeed, like the MOPR,¹⁶⁸ Capacity Repricing is not intended to upset the use of self-supply to meet a load-serving entity's capacity needs.

PJM proposes to limit this exclusion to two types of Capacity Market Sellers: “Municipal/Cooperative Entit[ies]” and “Vertically Integrated Utilit[ies].”¹⁶⁹ “Municipal/Cooperative Entit[ies]” would be defined as “cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.”¹⁷⁰ And, “Vertically Integrated Utility” would be defined as “a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.”¹⁷¹ The Self-Supply Exemption the Commission approved in Docket No. ER13-535 explicitly applied to these same types of entities.¹⁷²

As a general matter, these entities are appropriately excluded, because their traditional business models for capacity procurement do not give rise to concerns related

¹⁶⁷ See May 2013 Order at PP 107-08; *see also id.* at PP 110-12 (rejecting arguments that proposed self-supply exemption is unreasonable).

¹⁶⁸ See *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 242 (2011) (“[T]he MOPR was not intended to change the long-standing business models parties use to support investment in specific capacity procurement projects.”).

¹⁶⁹ See proposed PJM Tariff, Attachment DD § 5.14(j)(2)(c) (Option A).

¹⁷⁰ See proposed PJM Tariff, Attachment DD § 5.14(j)(2)(c) (Option A).

¹⁷¹ See proposed PJM Tariff, Attachment DD § 5.14(j)(2)(c) (Option A).

¹⁷² See May 2013 Order at PP 66, 107. Similar to the Commission's ultimate handling of the Competitive Entry Exemption on remand in Docket No. ER13-535, the Commission ultimately rejected the Self-Supply Exemption, but not in substance and without prejudice. *See* Remand Order at P 2.

to artificial price suppression. Indeed, the Commission has found that “[a]n uneconomic new entry strategy by a vertically-integrated utility, for example, poses a substantial risk of increasing its net costs,”¹⁷³ and, therefore, “these entities are unlikely to depend on costly strategies to address the non-self-supply portion of their portfolio.”¹⁷⁴

The fact that PJM is proposing to extend its approach to addressing price suppression to cover existing resources in addition to new resources obviates the need for the net short and net long thresholds that the Commission previously found appropriate for exempting self-supply sellers from the MOPR.¹⁷⁵ These thresholds sought to prevent a seller from offering uneconomic new entry to lower capacity costs, while simultaneously obtaining an economic benefit.

As explained, the current focus solely on new entry is now misplaced and those thresholds can no longer function as intended. Indeed, a purpose of the net long threshold was to serve to limit a self-supply entity from substantially overbuilding while recognizing that the addition of a large resource that may be efficiently sized to accommodate the LSE’s long-term needs may put the LSE in a net long position at the beginning of the resource’s life. Application of such a threshold to existing resources would not advance this rationale.

Further, application of net short and net long thresholds are unworkable under a scheme that looks at existing as well as new resources. For example, if a seller is in fact, net long on capacity (i.e., the LSE may have such a relatively large amount of excess

¹⁷³ May 2013 Order at P 111.

¹⁷⁴ May 2013 Order at P 111.

¹⁷⁵ May 2013 Order at P 107 (“We find that PJM’s proposed net-short and net-long thresholds, in principle, adequately protect the market from the price effects attributable to uneconomic new self-supply.”).

capacity that it may seek to “dump” capacity on the BRA, pushing down capacity prices in the process), it is not possible to determine which resources in the seller’s portfolio are the “excess” capacity not needed to meet the needs of its retail demand and thus should be designated for repricing and which resources are needed to meet load and should not be repriced. Any such determination would be inherently subjective and arbitrary.

Instead of struggling with trying to fit the square peg applicable net short/long tests into the round hole of entire generation portfolios, the Commission should turn to the data. As detailed in the Base Residual Auction reports for the seven years that the MOPR Self-Supply Exemption was in effect, as presented in Table 1, the data shows that new entry offers from this class of sellers is only a very small slice of RPM offers.¹⁷⁶

Table 1; Usage of MOPR Self-Supply Exemption¹⁷⁷

| BRA Auction Year | LDA | Requested Quantity (ICAP MW) | Granted Quantity (ICAP MW) | Cleared Quantity (ICAP MW) | BRA Report Page |
|-------------------------|------------|-------------------------------------|-----------------------------------|-----------------------------------|------------------------|
| 2020/2021 | RTO | 0 | 0 | 0 | 5 |
| 2019/2020 | RTO | 1,827.2 | 1,827.2 | 1,779.5 | 7 |
| 2019/2020 | MAAC | 0 | 0 | 0 | 7 |
| 2018/2019 | RTO | 0 | 0 | 0 | 7 |
| 2018/2019 | MAAC | 0 | 0 | 0 | 7 |
| 2017/2018 | | 940.0 | 940.0 | 940.0 | 7 |
| 2016/2017 | | 1,432.5 | 1,432.5 | 1,432.5 | 4 |

Thus, the Self-Supply Exemption has not been a vehicle for self-supply entities to clear new resources and meet their capacity needs. Rather, it appears that most sellers, if and

¹⁷⁶ PJM’s Base Residual Auction reports are posted on PJM’s website. *Capacity Market (RPM)*, PJM Interconnection, L.L.C., <http://www.pjm.com/markets-and-operations/rpm.aspx> (last visited Apr. 2, 2018) (under “Delivery Years” section, click on specific year, and click “Report” under “Base Residual Auction”).

¹⁷⁷ The Base Residual Auction reports for the 2016/2017 and 2017/2018 Delivery Years do not specify the LDA in which the Self-Supply Exemption was requested.

when given the choice, opted for a Competitive Entry Exemption over the Self-Supply Exemption. Table 2 below shows the megawatts of new entry the obtained a Competitive Entry Exemption and the subset of such resources that cleared.

Table 2; Usage of MOPR Competitive Entry Exemption¹⁷⁸

| BRA Auction Year | LDA | Requested Quantity (ICAP MW) | Granted Quantity (ICAP MW) | Cleared Quantity (ICAP MW) | BRA Report Page |
|-------------------------|------------|-------------------------------------|-----------------------------------|-----------------------------------|------------------------|
| 2020/2021 | RTO | 12,161.0 | 12,161.0 | 2,675.6 | 5 |
| 2019/2020 | RTO | 5,401.0 | 5,401.0 | 1,933.0 | 7 |
| 2019/2020 | MAAC | 5,764.0 | 5,764.0 | 1,870.9 | 7 |
| 2018/2019 | RTO | 7,177.0 | 7,177.0 | 2,311.2 | 7 |
| 2018/2019 | MAAC | 6,353.5 | 6,353.5 | 1,206.8 | 7 |
| 2017/2018 | | 13,089.8 | 13,089.8 | 4,230.0 | 7 |
| 2016/2017 | | 11,820.6 | 11,820.6 | 3,482.1 | 4 |

A comparison of Tables 1 and 2 shows that many more megawatts have offered and cleared under Competitive Entry Exemptions than Self-Supply Exemptions.

Given that PJM's proposed definition of Material Subsidy generally matches the definition of subsidies that disqualify resources from obtaining a MOPR Competitive Entry Exemption, there will likely be significant overlap in the resources that would fail to obtain a Competitive Entry Exemption and would have been mitigated to the MOPR Floor Offer Price and those resources that would be repriced under PJM's proposal. Conversely, resources that would have been able to obtain a Competitive Entry Exemption (because they are not receiving impermissible out of market subsidies) likewise would not be Capacity Resources with Actionable Subsidy and would not be repriced.

¹⁷⁸ The Base Residual Auction reports for the 2016/2017 and 2017/2018 Delivery Years do not specify the LDA in which the Competitive Entry Exemption was requested.

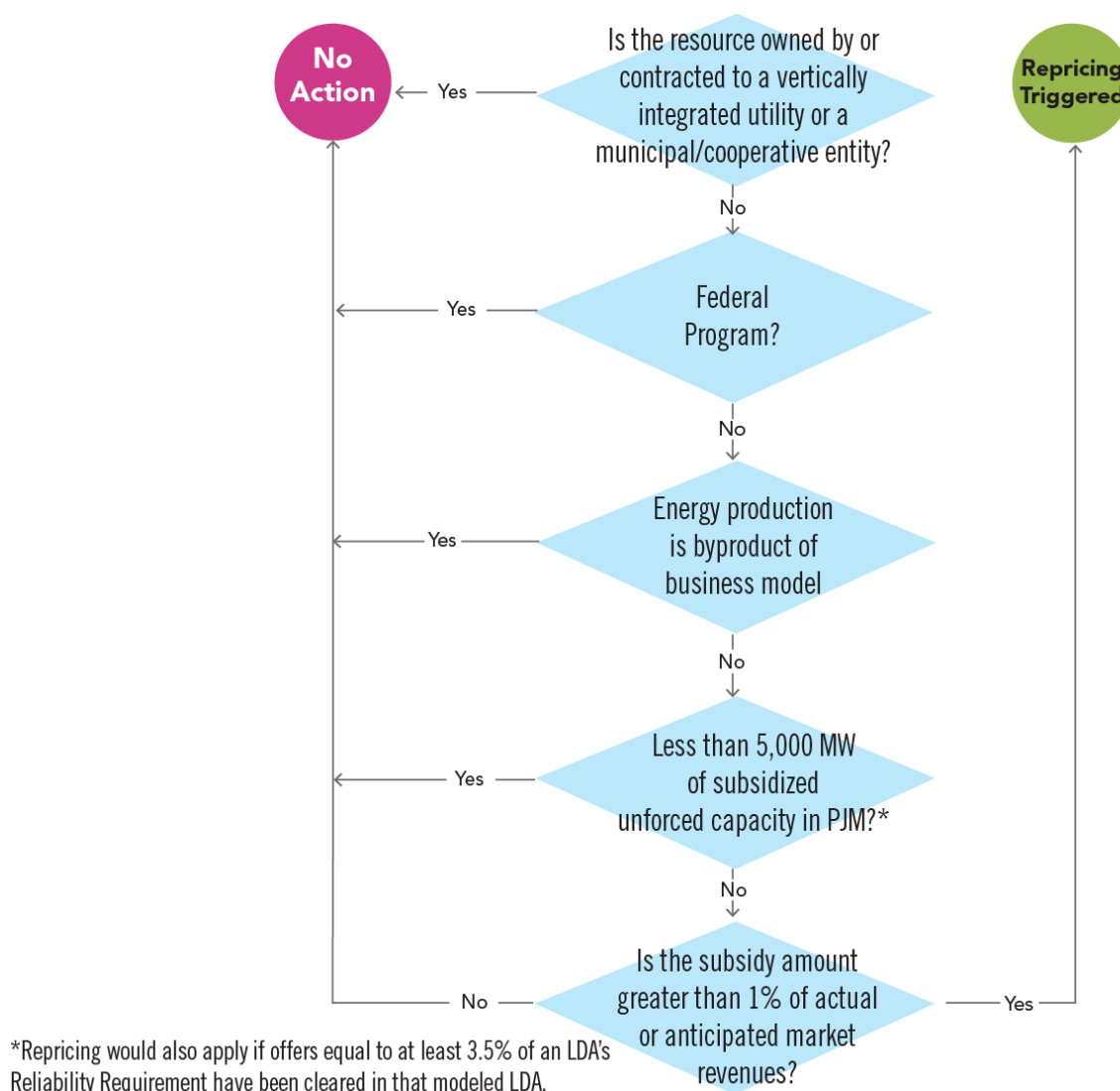
Accordingly, PJM’s proposal to not establish bounds on acceptable resource portfolios of “Municipal/Cooperative Entities” and “Vertically Integrated Utilities” relative to their retail load obligations is not a change that would have a measureable impact on the market.

Further, excluding certain Capacity Market Sellers that historically self-supply much of their capacity needs is consistent with other RPM market rules that allow such a seller to “indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid.”¹⁷⁹ And, “if the LSE indicated that it is committing the resource regardless of clearing price, [PJM] will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year.”¹⁸⁰

The decision tree shown in Figure 7 below illustrates the flow of criteria a resource would look to once it has received a Material Subsidy to determine if it has a Capacity Resource with Actionable Subsidy.

¹⁷⁹ PJM Tariff, Attachment DD § 5.2 (emphasis omitted).

¹⁸⁰ PJM Tariff, Attachment DD § 5.2 (emphasis omitted). As noted in section III.C.8 *infra*, PJM is changing the reference to the MOPR in this section 5.2 from “Any such Sell Offer shall be subject to the minimum offer price rule set forth in section 5.14(h)” to “Any such Sell Offer shall be subject to the repricing provisions of section 5.14(j).” See proposed PJM Tariff, Attachment DD § 5.2 (Option A).

Figure 7; Capacity Resource with Actionable Subsidy Decision Tree

In sum, PJM is proposing a narrow path for resources to become a Capacity Resource with Actionable Subsidy, and in so doing, PJM is ensuring that only those resources that receive subsidies with the most potential to negatively impact auction clearing prices will be repriced.

b. Process for Support and Review of Certification as Capacity Resource with Actionable Subsidy

Because each seller knows best whether any of its Capacity Resources meet the criteria for being a Capacity Resource with Actionable Subsidy, PJM is relying on sellers

to essentially “self-certify” the status of their resources.¹⁸¹ Specifically, for each Capacity Resource offered into a BRA, an officer of the seller “must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy in accordance with section 5.14(j)(2), and if not, the officer must certify as to which criteria does not apply to the Capacity Resource.”¹⁸²

In addition, each seller will provide PJM and the IMM, regarding each Demand Resource and Generation Capacity Resource (or uprate), “information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy.”¹⁸³ While the requisite information will be explained in greater detail in the PJM Manuals, generally the seller should provide information regarding any subsidy associated with the resource so as to illuminate whether such subsidy is a Material Subsidy and whether it amounts to more than 1% of the resource’s revenues.¹⁸⁴ The seller should provide such information to PJM and the IMM by no later than 120 days before the Base Residual Auction.¹⁸⁵ To ensure that a resource is properly considered a Capacity Resource with Actionable Subsidy, sellers will have an ongoing obligation to promptly provide PJM and the IMM additional information, upon request.

Once a resource is deemed to be a Capacity Resource with Actionable Subsidy, that resource shall continue to be considered a Capacity Resource with Actionable Subsidy “unless and until the Capacity Market Seller provides notification of a change in

¹⁸¹ See *generally* proposed PJM Tariff, Attachment DD § 5.14(j)(3) (Option A).

¹⁸² See proposed PJM Tariff, Attachment DD § 5.14(j)(3)(b) (Option A).

¹⁸³ See proposed PJM Tariff, Attachment DD § 5.14(j)(3)(a) (Option A).

¹⁸⁴ *Id.*

¹⁸⁵ *Id.*

such status or the Office of the Interconnection removes such status pursuant to [a PJM determination of fraud or material misrepresentation], or by Commission order.”¹⁸⁶ Sellers will have a continuing obligation to notify PJM and the IMM of any material changes in the qualifications of the resource.¹⁸⁷

4. *Determination of Actionable Subsidy Reference Price*

To perform the second stage in the auction and re-run the optimization algorithm to determine the appropriate Capacity Resource Clearing Prices, PJM will substitute competitive offer prices for the prices initially submitted for the Capacity Resources with Actionable Subsidy that cleared in the auction’s first stage. The substitute, competitive offer price will be the Actionable Subsidy Reference Price. This price will be determined differently based on whether the resource is an Existing Generation Capacity Resource, a Planned Generation Capacity Resource, or a Demand Resource, and based on the facts and circumstances specific to each Capacity Resource with Actionable Subsidy.

a. Existing Generation Capacity Resources

For existing Generation Capacity Resources, the Actionable Subsidy Reference Price shall be the “higher of”: (1) the resource’s Avoidable Cost Rate, whether determined on a resource-specific basis or as a default for that resource type; and (2) the resource’s opportunity cost of committing as Capacity Performance.¹⁸⁸ Either of these values would represent a competitive offer price for the subsidized resource and thereby allow the second stage of the auction to establish clearing prices based on competitive offers.

¹⁸⁶ *Id.*, Attachment DD § 5.14(j)(3)(c) (Option A).

¹⁸⁷ *Id.*

¹⁸⁸ *See* proposed PJM Tariff, Attachment DD § 5.14(j)(4)(a) (Option A).

The Avoidable Cost Rate is, by definition, a competitive, cost-based rate for a Capacity Resource, based on inputs appropriate for providing capacity to the PJM Region.¹⁸⁹ PJM is proposing two alternative means for selecting the Avoidable Cost Rate. First, the seller may elect to determine a resource-specific value that would be determined “without consideration of any Material Subsidy . . . [and] in accordance with the procedures and standards of Tariff, Attachment DD, sections 6.4, 6.7, and 6.8.”¹⁹⁰ Such value would include “a risk premium for assuming a Capacity Performance obligation and [would be] net of Projected PJM Market Revenues.”¹⁹¹

Alternatively, if the seller is not willing or able to obtain a resource-specific Avoidable Cost Rate, a default value based on the resource type could be used. Historically, most existing resource types in PJM were offer capped at default Maximum Avoidable Cost Rates as stated in the PJM Tariff or posted on PJM’s website.¹⁹² PJM proposes to carry forward this accepted practice and rely on stated maximum Avoidable Cost Rates for existing resources in the event that PJM is unable to determine a suitable Avoidable Cost Rate. The Actionable Resource Reference Price will be the higher of the resource’s Avoidable Cost Rate (whether a determined or default value) and the resource’s opportunity cost.

However, given that the transition to 100% Capacity Performance Resources required adoption of the current Market Seller Offer Cap, PJM no longer calculates and posts default Avoidable Cost Rates. Accordingly, to ensure that such values are posted

¹⁸⁹ See PJM Tariff § 1, Definitions A-B; *id.*, Attachment DD § 6.8(a).

¹⁹⁰ See proposed PJM Tariff, Attachment DD § 5.14(j)(4)(a)(i)(B)(1) (Option A).

¹⁹¹ See proposed PJM Tariff, Attachment DD § 5.14(j)(4)(a)(i)(B)(1) (Option A).

¹⁹² See PJM Tariff, Attachment DD § 6.7(c)(ii).

for each resource type, including nuclear, solar, and wind resources, PJM is proposing to add a requirement that PJM calculate and post such values. PJM is proposing to continue PJM's prior process of annually adjusting the values, as follows:

For each Base Residual Auction, [PJM] shall use the values stated in Tariff, Attachment DD, section 6.7(c)(ii) and adjust them based on the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission ("Handy-Whitman Index") to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The default Avoidable Cost Rates shall be expressed in dollar values for the applicable Delivery Year.¹⁹³

This provision mirrors the prior requirement for the 2017/2018 Delivery Year and that is still stated in Attachment DD, section 6.7(c)(ii). By keying the annual changes to the publically available Handy-Whitman Index, the value determination is transparent.¹⁹⁴ The starting values for the default Avoidable Cost Rates are the values for the 2016/2017 Delivery Year as stated in the table in Attachment DD, section 6.7(c)(ii).

Because the tariff does not state default Avoidable Cost Rate values for nuclear, wind, and solar resource types, PJM has determined preliminary retirement ACR values for these resource types, as shown in Table 3 below.

¹⁹³ See proposed PJM Tariff, Attachment DD § 5.14(j)(4)(a)(i)(B) (Option A).

¹⁹⁴ See *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183, at P 106 (2014) ("PJM's proposed labor construction values closely track publicly-available data and thus have the benefit of being transparent.").

Table 3; Preliminary Default Retirement ACR Values for Nuclear, Wind, and Solar Resource Types

| | 2022/2023 Delivery Year Retirement ACR UCAP (\$/MW-Day) |
|------------------|---|
| Nuclear – single | \$706 |
| Nuclear – dual | \$663 |
| Onshore wind | \$503 |
| Solar PV | \$185 |

These values are based on information from a data base of the Environmental Protection Agency (“EPA”).¹⁹⁵ The data relied on includes the fixed operating and maintenance expense (“FOM”) of existing units. The EPA data base utilizes model plants to represent aggregations of actual individual generating units. Units with similar characteristics are grouped for representation by model plants with a combined capacity and weighted-average characteristics that are representative of all the units comprising the model plant. Except for existing nuclear units, PJM averaged the FOM costs for the model plants in the PJM Region. PJM obtained existing nuclear unit FOM data from Table 4-34 “Characteristics of Existing Nuclear Units” of the EPA Base Case.

Because the EPA’s data are presented in 2011 dollars, PJM needed to escalate the value to 2022/2023 dollars, as that is the relevant Delivery Year. To do so, first PJM escalated them from 2011 to 2016 by historical year by year escalation using the HWI-Total Steam Production Plant Index for North Atlantic Region. Then, consistent with PJM’s longstanding practice of escalating ACR values for future years, PJM used “the

¹⁹⁵ See *Clean Air Markets*, EPA, https://www.epa.gov/sites/production/files/2016-12/epa_base_case_v.5.16_for_2015_ozone_naaqs_transport_noda.zip (open zip file titled “EPA Base Case v.5.16 for 2015 Ozone NAAQS Transport NODA DAT File” then document titled “EPA Base Case v.5.16 for 2015 Ozone NAAQS Transport NODA DAT Replacement File”).

most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index.”¹⁹⁶ PJM determined 3.4% to be the 10-year average HWI-Total Steam Production Plant Index for North Atlantic Region escalation rate for the 2007-2016 period. Combined these two escalations (for 2011-2016 and for 2016-2022) are equivalent to factor of 1.38. Thus, to arrive at the values stated in the above table, PJM multiplied the 2011 EPA values by 1.38.

While this preliminary analysis is well-supported and results in values that would be just and reasonable for the limited purpose of setting default ACR values, PJM does not view this analysis as the last word. PJM would expect to review and revisit these values as PJM gains more experience with applying the Actionable Subsidy Reference Price to the particular resources in the PJM Region that become subject to Capacity Repricing.

The other value to be considered in determining the Actionable Subsidy Reference Price for an Existing Generation Resource is “the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap.”¹⁹⁷ That is, PJM would take the higher of the Avoidable Cost Rate and the specific resource’s opportunity cost, i.e., the value of Performance Bonus Payments earned from performing during emergencies when the resource is not required to perform to meet any capacity commitments.¹⁹⁸ When calculating such an offer price, the seller must “employ[]

¹⁹⁶ See PJM Tariff, Attachment DD, section 6.7(c)(ii).

¹⁹⁷ Proposed PJM Tariff, Attachment DD § 5.14(j)(4)(a)(i)(A) (Option A).

¹⁹⁸ See *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at PP 335-38 (2015) (“Capacity Performance Order”), *order on reh’g*, 155 FERC ¶ 61,157 (2016)

alternative assumptions” than used in determining the Market Seller Offer Cap for certain inputs “based on the actual market conditions and the actual circumstances of the unit.”¹⁹⁹ Specifically, the seller must use actual values for “the availability ratio, the number of Performance Assessment Hours, the Balancing Ratio, and the Capacity Performance bonus payment rate.”²⁰⁰ This competitive price formulation of existing resources generally tracks the formulation of RPM’s Market Seller Offer Cap as it includes “the marginal and opportunity costs faced by a[n existing] resource.”²⁰¹

Finally, by using the “higher of” of these two values as the Actionable Subsidy Reference Price, PJM’s proposal follows the logic underlying the Market Seller Offer Cap.²⁰² As the Commission explained, the offer cap “reflect[s] the opportunity cost that a resource faces when choosing to become a capacity resource,”²⁰³ where the opportunity cost is “the expected reduction in Performance Bonus Payments and/or increased Non-Performance Charges that a resource would experience by becoming a capacity resource rather than remaining a non-capacity resource.”²⁰⁴ However, because some resources may have an Avoidable Cost Rate higher than the offer cap value, the Commission accepted PJM’s proposal “to allow a resource with a higher avoidable cost rate to submit

(“Capacity Performance Rehearing Order”), *appeal denied*, *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656 (D.C. Cir. 2017).

¹⁹⁹ Proposed PJM Tariff, Attachment DD, section 5.14(j)(4)(b)(i) (Option A).

²⁰⁰ *Id.*

²⁰¹ Capacity Performance Order at P 335.

²⁰² *See* Capacity Performance Order at PP 334-58; Capacity Performance Rehearing Order at PP 182-96.

²⁰³ Capacity Performance Rehearing Order at P 175.

²⁰⁴ Capacity Performance Rehearing Order at P 175. In the Commission’s parlance in its order accepting the current Market Seller Offer Cap, such a cap represents a rational offer for a “Low ACR Resource,” i.e., a resource.

data supporting a unit-specific offer cap that details all Avoidable Cost Rate components, including a quantifiable risk premium.”²⁰⁵ Thus, the current Market Seller Offer Cap and PJM’s Actionable Subsidy Reference Price recognize that the competitive price for Existing Generation Resources may vary depending on the resource’s allowable avoidable costs and its risk exposure.

However, in the event that there is no Avoidable Cost Rate obtainable for a resource (i.e., the resource-specific Avoidable Cost Rate cannot be determined and there is no default value for that resource type), then the Actionable Subsidy Reference Price for the resource will be PJM’s default Market Seller Offer Cap, which is the Net Cost of New Entry (“CONE”) times the Balancing Ratio (i.e., Net CONE*B). No comparison of the offer cap to opportunity cost will be made, because it already includes such costs.

b. Planned Generation Capacity Resources

For Planned Generation Resources, as above, PJM is proposing to use “higher of” the resource’s costs, which includes a risk premium for assuming a Capacity Performance obligation and net of Projected PJM Market Revenues, or its opportunity costs to determine a resource’s Actionable Subsidy Reference Price. However, because the cost data for determining the Avoidable Cost Rate is not available, PJM is proposing to employ the Commission-approved MOPR unit-specific exception provisions for determining a planned resource’s unit-specific costs.²⁰⁶ Under these provisions, the seller must submit to both PJM and the IMM a request for “a determination of a unit-specific offer price that is consistent with the competitive, cost-based, fixed, net cost of new entry

²⁰⁵ Capacity Performance Rehearing Order at P 175; *see also* Capacity Performance Order at PP 334-41.

²⁰⁶ Compare proposed PJM Tariff, Attachment DD § 5.14(j)(4)(b) (Option A), with *id.*, Attachment DD § 5.14(h)(6) (Option B).

were the resource to rely solely on revenues from PJM-administered markets.”²⁰⁷

Consistent with historic MOPR provisions,²⁰⁸ a seller must use the following financial modeling assumptions:

(i) nominal levelization of gross costs, (ii) asset life of 20 years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource.²⁰⁹

The seller must also provide supporting documentation for project costs and “identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its proposed Actionable Subsidy Reference Price.”²¹⁰ The seller shall also provide any additional supporting information reasonably sought PJM or the IMM to evaluate the request.

In the event PJM rejects a seller-proposed, unit-specific, cost-based price, the proposed tariff provides that PJM will inform a seller the reasons for the rejection and PJM “shall calculate and provide to such Capacity Market Seller, a corrected Actionable Subsidy Reference Price based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction.”²¹¹ By contrast, if PJM determines that the seller’s proffered reference price is

²⁰⁷ Proposed PJM Tariff, Attachment DD § 5.14(j)(4)(b)(i)(A) (Option A).

²⁰⁸ See *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 43 (2011); see also PJM Tariff, Attachment DD § 5.14(h).

²⁰⁹ Proposed PJM Tariff, Attachment DD § 5.14(j)(4)(b)(i)(B) (Option A).

²¹⁰ Proposed PJM Tariff, Attachment DD § 5.14(j)(4)(b)(i)(B) (Option A).

²¹¹ Proposed PJM Tariff, Attachment DD § 5.14(j)(4)(b)(i)(C) (Option A).

acceptable, PJM shall notify both the IMM and the seller no later than sixty days before the auction.²¹²

Once the unit-specific cost-based price is determined, PJM will compare that value to the resource's opportunity cost, which as for existing generation resources, shall be determined using the same method as for the Market Seller Offer Cap, but "based on the actual market conditions and the actual circumstances of the unit."²¹³ As noted, PJM's proposed approach of taking the higher of the resource's unit costs or opportunity costs is reasonable, as it parallels the approach used to determine the Market Seller Offer Cap.

As for existing generation resources, in the event that there is no Avoidable Cost Rate obtainable for a resource (i.e., the resource-specific Avoidable Cost Rate cannot be determined and there is no default value for that resource type), then the Actionable Subsidy Reference Price for the resource will be PJM's default Market Seller Offer Cap of Net CONE*B. No comparison of the offer cap to opportunity cost will be made.

c. Demand Resources

For Demand Resources, because the determination of an Avoidable Cost Rate generally is not feasible due to the inherent nature of the resource type, the Actionable Subsidy Reference Price shall be the Market Seller Offer Cap, i.e., Net CONE*B.²¹⁴ This is a reasonable option for repricing Demand Resources, as the Commission has already found Net CONE * B to represent a competitive offer price.²¹⁵

²¹² Proposed PJM Tariff, Attachment DD § 5.14(j)(4)(b)(i)(C) (Option A).

²¹³ Proposed PJM Tariff, Attachment DD § 5.14(j)(4)(a)(i)(A) (Option A).

²¹⁴ See proposed PJM Tariff, Attachment DD § 5.14(j)(4)(c) (Option A).

²¹⁵ See Capacity Performance Order at P 336.

d. The IMM Will Advise and Provide PJM Input on the Determination of Actionable Subsidy Reference Prices

In addition, to reflect the IMM's role in advising PJM in the determination of Actionable Subsidy Reference Prices, PJM is proposing conforming changes to the description of the IMM's role in the repricing administration process as set forth in Tariff, Attachment M-Appendix, Part II.D. In so doing, PJM is re-proposing the provisions previously accepted in Docket No. ER13-535 for administering the MOPR and modifying them for the repricing rules.²¹⁶

5. *Materiality Threshold*

As a transition mechanism, PJM is proposing materiality thresholds to trigger permanent implementation of the two-stage capacity auction approach for every BRA that clears any Capacity Resources with Actionable Subsidy. PJM is proposing a region-wide threshold such that PJM will not re-run the auction using repriced sell offers unless at least 5,000 MWs of Capacity Resources with Actionable Subsidy (in Unforced Capacity terms) clears across the entire PJM Region in the first stage. However, because price suppression may occur within a modeled LDA even before it occurs throughout the PJM Region, PJM is also proposing a targeted materiality threshold for modeled LDAs. Specifically, if Capacity Resources with Actionable Subsidy clear in a modeled LDA in an amount equal to or greater than 3.5% of that LDA's reliability requirement, then PJM will re-run the auction, after repricing all Capacity Resources with Actionable Subsidies that cleared in that LDA, to determine the Capacity Resource Clearing Price.

Because the price of a resource in an LDA may have impacts in other areas within PJM, the clearing prices established by any auction re-run will apply throughout the PJM

²¹⁶ See proposed PJM Tariff, Attachment M-Appendix § II.D (Option A).

Region. In other words, if the LDA threshold is met and the RTO threshold has yet to be met, the clearing prices determined in the second stage will apply to the RTO and any LDA that separates, regardless of whether there are Capacity Resources with Actionable Subsidy in that LDA. Because of the interdependent nature of capacity commitments as between the RTO region and the separately modeled LDAs, PJM is not able to re-run the auction with repricing applied to just a subset of LDAs. To attempt to execute such an auction in only a subset of LDAs would not provide a consistent result across all LDAs and the RTO.

These thresholds not only trigger the special Capacity Repricing rules after a material amount of subsidized resources clear an auction, they also provide a transition mechanism from the current rules' narrow focus on new resources of the current rules to more broadly being concerned about the impact of existing resource subsidization. Currently there is only about 3,079 megawatts of resources that could be considered Capacity Resources with Actionable Subsidy—an amount that is not sufficiently material to require action (i.e., repricing) looking at the 5,000 MW threshold for the RTO.²¹⁷ However, given political trends, it appears likely that a material amount of subsidized resources will exist in the near future. Accordingly, the proposed thresholds provide the market time to adjust to these new rules.

²¹⁷ See Keech Aff. ¶ 19. As Mr. Keech explains, PJM identified 1,674 MW of Capacity Resources with Actionable Subsidies in the ComEd LDA, which “exceeds 3.5% of the reliability requirement for that LDA, and thus would trigger repricing.” *Id.*

The Commission has often found such transitions to be a just and reasonable component of market rule reforms.²¹⁸ For example, in its recent order approving ISO New England’s CASPR proposal, the Commission found “ISO-NE’s transition proposal to be a balanced approach for implementing CASPR’s alternative means of accommodating state policies, while attenuating any potential adverse impacts on pending investments that could result from an immediate change to the market rules.”²¹⁹ Likewise, here, PJM’s proposal to apply Capacity Repricing only when actionable subsidization reaches a material level properly insulates the market from unnecessary action.

6. Special Procedures Applicable in Cases of Fraud or Misrepresentation Are Appropriate

PJM is proposing safeguard provisions to address the consequences if PJM reasonably believes that a previous determination of whether a resource is a Capacity Resource with Actionable Subsidy was based on fraudulent or material misrepresentations or omissions and, absent such misrepresentations or omissions, the resource’s Capacity Resource with Actionable Subsidy status would be different.²²⁰ The

²¹⁸ See, e.g., CASPR Order at P 100 (“[I]t is consistent with Commission precedent to permit a transition mechanism to a new regulatory construct.” (citing *ISO New England Inc.*, 155 FERC ¶ 61,319, at P 62 (2016) (approving the use of a transition mechanism for implementing zonal demand curves in ISO New England); *ISO New England Inc.*, 147 FERC ¶ 61,172, at P 73 (2013) (approving a transition plan to phase in ISO New England’s Pay for Performance provisions to allow parties to “gain experience with the new market design at a reduced risk exposure”)); see also Capacity Performance Order at P 243; Capacity Performance Rehearing Order at PP 164-73.

²¹⁹ CASPR Order at P 99.

²²⁰ See generally proposed PJM Tariff, Attachment DD § 5.14(j)(5) (Option A).

proposed provisions are modeled closely on the provisions the Commission previously accepted in Docket No. ER13-535.²²¹

Like those provisions, PJM is proposing that, if PJM suspects the misrepresentation or omission sufficiently in advance of the start of the auction, it can alter the Capacity Resource with Actionable Subsidy determination for that auction,²²² but to exercise this remedy PJM must notify the market seller in writing of the change in status no later than sixty days before the start of the offer period for the auction.²²³ If a resource is suspected of being a Capacity Resource with Actionable Subsidy, both PJM and the IMM may request information from the seller to determine an appropriate Actionable Subsidy Reference Price for such resource.²²⁴ If it exercises this remedy, PJM will make any filings with the Commission that PJM deems necessary.

The proposed provisions provide that if PJM fails to provide written notice of suspected fraudulent or material misrepresentation or omission at least thirty days before the start of the relevant Base Residual Auction, then PJM may file with the Commission the suspect certification that contains any fraudulent or material misrepresentation or

²²¹ See May 2013 Order at P 115.

²²² In other words, if PJM determines that if a resource (a) *does not* qualify as a Capacity Resource with Actionable Subsidy, but was self-certified as a Capacity Resource with Actionable Subsidy, then such resource will not be repriced in stage two of the auction or (b) *does* qualify as a Capacity Resource with Actionable Subsidy, but was self-certified as not a Capacity Resource with Actionable Subsidy, then such resource will be repriced in stage two of the auction. See proposed PJM Tariff, Attachment DD § 5.14(j)(5)(a) (Option A).

²²³ See proposed PJM Tariff, Attachment DD § 5.14(j)(5)(a) (Option A).

²²⁴ See proposed PJM Tariff, Attachment DD § 5.14(j)(5)(a) (Option A).

omission.²²⁵ PJM will implement any Commission directive with respect to such suspect certification.

In any event, before PJM exercises its authority to timely alter a resource's status or before PJM submits a filing to the Commission concerning such remedy, PJM is to notify the seller and "to the extent practicable," provide the seller an opportunity to explain the alleged misrepresentation or omission.²²⁶ The proposed Tariff adds that the seller may submit a revised certification for that Capacity Resource for subsequent RPM auctions, including RPM Auctions held during the pendency of a FERC proceeding.²²⁷

Finally, PJM will seek fast-track treatment for any such filing, and reveal neither the name nor any identifying characteristics of the seller or its resource, though the filing shall otherwise be public.²²⁸

7. *Eliminating the Minimum Offer Price Rule*

Should the Commission accept PJM's Capacity Repricing rules, which apply to both new and existing resources, PJM's MOPR rules would no longer be needed. Thus, PJM is proposing to eliminate the current MOPR provisions. PJM proposes to make such elimination coincident with the effectiveness of the Capacity Repricing rules.

8. *Conforming Tariff Revisions*

PJM is also making conforming revisions to Tariff, Attachment DD, sections 5.2 and 5.11 and to the provisions granting the IMM authority to review and advise on MOPR determinations in section II.D of Attachment M-Appendix to reflect the removal

²²⁵ See proposed PJM Tariff, Attachment DD § 5.14(j)(5)(b) (Option A).

²²⁶ Proposed PJM Tariff, Attachment DD § 5.14(j)(5)(c) (Option A).

²²⁷ See proposed PJM Tariff, Attachment DD § 5.14(j)(5)(c) (Option A).

²²⁸ See proposed PJM Tariff, Attachment DD § 5.14(j)(5)(c) (Option A).

of the MOPR and addition of Capacity Repricing.²²⁹ Generally, these conforming revisions merely replace MOPR references with references to the Capacity Repricing rules instead. However, PJM is also proposing a new Attachment M-Appendix, section II.D-1 that allows the IMM to review a seller's certification of whether a resource is a Capacity Resource with Actionable Subsidy for fraud and material misrepresentation or omission.²³⁰ This provision is based on the provision accepted by the Commission in Docket No. ER13-535 that authorized the IMM to conduct a similar review of MOPR exemption and exception requests.²³¹

Finally, PJM is proposing to update the Definitions section of its tariff to state that “‘Capacity Resource with Actionable Subsidy’ or ‘Capacity Resources with Actionable Subsidies’ shall have the meaning provided in Tariff, Attachment DD, section 5.14(j)” and “Actionable Subsidy Reference Price shall have the meaning provided in Tariff, Attachment DD, section 5.14(j).”²³²

D. Option B: MOPR-Ex, Extension of the Minimum Offer Price Rule to Mitigate Certain Resources *Before* They Clear in an RPM Auction

PJM's alternative approach to addressing the impacts of state resource decisions on PJM's capacity market is MOPR-Ex. Under MOPR-Ex, PJM is proposing to extend the Minimum Offer Price Rule to cover existing resources that may receive material state subsidies. This approach is mitigative in nature, as opposed to Capacity Repricing's

²²⁹ See proposed PJM Tariff, Attachment DD §§ 5.2, 5.11 (Option A); *id.*, Attachment M-Appendix §§ II.D, D-1 (Option A).

²³⁰ See proposed PJM Tariff, Attachment M-Appendix § II.D-1 (Option A).

²³¹ See PJM Tariff, Attachment M-Appendix § II.D.3 (language in effect prior to Remand Order).

²³² See proposed PJM Tariff §§ 1, Definitions A-B, C-D (Option A).

accommodative approach, in that it alters sellers' subsidized offer prices *before* PJM runs the auction and assigns capacity commitments.²³³

The MOPR has been part of the RPM framework from the beginning, but has twice undergone significant revisions. In Docket No. ER11-2875, the Commission accepted PJM's proposal to strengthen the MOPR's protections against buyer-side market power in the face of state subsidies.²³⁴ In Docket No. ER13-535, the Commission accepted PJM's proposal, under FPA section 205, to change the structure of the MOPR to provide two categorical exemptions to the MOPR for certain types of sellers and resources that do not present price suppression concerns.²³⁵ However, the Commission conditioned its acceptance PJM agreeing to retain the Unit-Specific Exception to allow "resources that have lower competitive costs than the default offer floor . . . [to] have the opportunity to demonstrate their competitive entry cost" and offer in at below the MOPR floor offer price."²³⁶ On appeal, the *NRG* court found that FERC exceeded its authority under FPA section 205 by imposing a more than "minor" modifications to PJM's proposal by requiring retention of the unit-specific exception.²³⁷ On remand, the Commission rejected PJM's proposal, in its entirety, on the sole grounds that PJM did not propose, in the first instance, to retain the unit-specific exception alongside the

²³³ Consistent with the current MOPR, PJM is proposing that MOPR-Ex would apply in all RPM Auctions, unlike Capacity Repricing, which would apply only to Base Residual Auctions as explained in section III.C.2 above.

²³⁴ *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, *order on reh'g*, 137 FERC ¶ 61,145 (2011), *aff'd sub nom. NJBPU*.

²³⁵ See May 2013 Order at PP 53, 107; October 2015 Order at PP 32, 52.

²³⁶ May 2013 Order at P 141.

²³⁷ *NRG*, 862 F.3d at 116.

categorical exemptions.²³⁸ However, the Commission stated that such rejection is “without prejudice” to PJM submitting a new proposal that will “cure the deficiencies” i.e., retain the unit-specific exception.²³⁹

Throughout all these changes, the MOPR has only applied to resources seeking to offer into PJM’s capacity market for the first time, i.e., “new entry,” and was limited only to certain gas-fired generation resources located in the PJM Region.

Now, faced with the growing practice of state subsidies for existing resources, the MOPR-Ex would alter the scope of the MOPR, as detailed below. First, MOPR-Ex would apply to new *and existing* resources, whereas the MOPR applied only to new resources. Second, whereas MOPR has long applied to new resources regardless of whether any subsidy is received, MOPR-Ex would explicitly target *only* those resources receiving a Material Subsidy and that qualifies as a Capacity Resource with Actionable Subsidy. Third, while historically the MOPR applied to only certain types of gas-fueled generation resources, i.e., combustion turbine, combined cycle, and for the past seven years, integrated gasification combined cycle, PJM is proposing MOPR-Ex would apply to *all* types of Generation Capacity Resources, regardless of fuel, unless the resource is a

²³⁸ Remand Order at P 43 (“[W]e find that PJM’s proposed changes are not just and reasonable standing alone, and that while the categorical exemptions will generally allow qualifying market participants to avoid the need of seeking a unit-specific review of their offers[,] . . . some resources . . . may nonetheless have competitive costs that fall below the benchmark price.” (second alteration in original) (internal quotation marks omitted) (footnote omitted)).

²³⁹ Remand Order at P 2. As directed, PJM submitted a compliance filing removing all the MOPR revisions accepted in Docket No. ER13-535. *See* Compliance Filing Concerning PJM’s Minimum Offer Price Rule of PJM Interconnection, L.L.C., Docket No. ER13-535-006 (Jan. 9, 2018). Accordingly, the current-effective MOPR is the same as the one the Commission accepted in Docket No. ER11-2875.

Qualifying Facility.²⁴⁰ Finally, the proposed MOPR-Ex would extend the geographic reach of the MOPR beyond the boundaries of the PJM Region to external Capacity Resources. Each of these changes is designed to address the targeted state subsidies that can have direct impact on the BRA clearing price.

In addition to the change in scope, MOPR-Ex expands on the MOPR's historic practice of categorically exempting certain resources based on the characteristics of the seller or resource. Thus, consistent with the historic MOPR design, PJM is proposing to retain the Unit-Specific Exception to allow Capacity Resources with Actionable Subsidy, new and existing, to be able to offer below the MOPR Floor Offer Price. Complementing retention of the Unit-Specific Exception for sellers to avoid the MOPR Floor Offer Price, PJM is also proposing to re-establish that categorical exemptions can preclude resources from being subject to the MOPR. The result is the same as under the MOPR provisions initially accepted in Docket No. ER13-535—for any resource that a seller has obtained a categorical exemption that resource will be allowed to submit an unmitigated offer price. PJM is proposing four categorical exemptions from being a Capacity Resource with Actionable Subsidy.

1. MOPR-Ex Would Apply Only to a Capacity Resource with Actionable Subsidy

Just as under the Capacity Repricing approach, PJM is proposing that MOPR-Ex would apply only to Capacity Resources with Actionable Subsidy.²⁴¹ However, under

²⁴⁰ Unlike the MOPR accepted in Docket No. ER13-535, MOPR-Ex will apply to Generation Capacity Resources and uprates to such resources with an Unforced Capacity of less than 20 MW. In other words, there is no resource size threshold that must be met before MOPR will be triggered.

²⁴¹ As with Capacity Repricing, PJM is proposing as part of MOPR-Ex to update the Definitions section of its Tariff to state that “Capacity Resource with Actionable

MOPR-Ex, sellers of such resources may be able to offer below the MOPR Floor Offer Price by obtaining a unit-specific exception. Thus, PJM is proposing that:

Any Sell Offer based on a Capacity Resource with Actionable Subsidy submitted in any RPM Auction shall have an offer price no lower than the MOPR Floor Offer Price, unless the Capacity Market Seller has obtained a Unit-Specific Exception with respect to such Capacity Resource with Actionable Subsidy in such auction prior to the submission of such offer in accordance with the provisions of this subsection 5.14(h).²⁴²

The path for determining a Capacity Resource with Actionable Subsidy generally mirrors that PJM is proposing under Capacity Repricing. Thus, to ensure that only those generation resources that receive a subsidy that warrant action based on design or market impact, PJM is proposing a narrow path for a resource to qualify as a Capacity Resource with Actionable Subsidy. And, resources are presumed not to be a Capacity Resource with Actionable Subsidy, unless the stated criteria are met.

a. The Seller Must Receive a Material Subsidy

To qualify as a Capacity Resource with Actionable Subsidy, the resource's seller must receive a Material Subsidy.²⁴³ Recognizing that not every subsidy impacts the seller's offer to a degree that materially affects its offer price, PJM is proposing a definition for Material Subsidies that includes those impactful, material subsidies and specifically excludes other, non-actionable subsidies.²⁴⁴ In this vein, PJM is proposing to adopt the same definition for Material Subsidy for MOPR-Ex as the Commission previously accepted for obtaining a Competitive Entry Exemption from the MOPR in

Subsidy shall have the meaning provided in Tariff, Attachment DD, section 5.14(h)(2).” See proposed PJM Tariff § 1, Definitions C-D (Option B).

²⁴² Proposed PJM Tariff, Attachment DD § 5.14(h)(1) (Option B).

²⁴³ Proposed PJM Tariff, Attachment DD § 5.14(h)(2)(b) (Option B).

²⁴⁴ Proposed PJM Tariff § 1, Definitions L-M-N (Option B).

Docket No. ER15-535²⁴⁵ (and as PJM is proposing for Capacity Repricing²⁴⁶). Thus, for example, sellers that receive “material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource” will be deemed to receive a Material Subsidy.²⁴⁷

b. Applicable Resource Types

Since its inception, the MOPR has only applied to certain types of Generation Capacity Resource.²⁴⁸ However, given that PJM is observing sellers of non-gas-fired generation facilities receiving Material Subsidies (such as nuclear resources under the Illinois ZEC program), PJM is proposing that MOPR-Ex would apply to all Generation Capacity Resources, including planned uprates, regardless of fuel type.²⁴⁹ But, PJM is proposing one exception. If the resource is a Qualifying Facility, it is excluded from being a Capacity Resource with Actionable Subsidy.²⁵⁰ This exclusion is consistent with the Commission’s prior acceptance to exclude Qualifying Facilities from the MOPR.²⁵¹

²⁴⁵ See May 2013 Order at P 54; PJM Tariff, Attachment DD § 5.14(h)(7)(iii) (language in effect prior to Remand Order).

²⁴⁶ Compare proposed PJM Tariff § 1, Definitions L-M-N (Option A), with *id.* § 1, Definitions L-M-N (Option B). For a more detailed description of what constitutes a Material Subsidy, see section III.C.3.a.i above.

²⁴⁷ Proposed PJM Tariff § 1, Definitions L-M-N (Option B).

²⁴⁸ See May 2013 Order at P 146; October 2015 Order at PP 66-67.

²⁴⁹ See proposed PJM Tariff, Attachment DD § 5.14(h)(2)(a) (Option B).

²⁵⁰ See proposed PJM Tariff, Attachment DD § 5.14(h)(2)(c) (Option B).

²⁵¹ See May 2013 Order at P 169; Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER13-535-003, at 12 (June 3, 2013) (“June 2013 Compliance Filing”); *id.* at Attachment B (clean tariff sheets); October 2015 Order at P 108.

c. Categorical Exemptions that Preclude Resources from Qualifying as a Capacity Resource with Actionable Subsidy

Given that the purpose of the MOPR-Ex is to address the price suppressive effects of material state subsidies on RPM Auction clearing prices, PJM is proposing to exclude from the definition of Capacity Resource with Actionable Subsidy the types of resources that are not likely to raise price suppression concerns. PJM proposes to accomplish such exclusion by establishing (or in some cases re-establishing) categorical exemptions to provide an objective, transparent process for sellers of resources that receive a Material Subsidy to demonstrate that Sell Offers for such resources do not raise price suppression concerns based on the characteristics of the seller or the applicable Material Subsidy. Specifically, PJM is re-proposing the Self-Supply and Competitive Entry Exemptions that were initially approved in Docket No. ER13-535 and were in place for seven years of RPM Auctions. In addition, PJM is proposing two new categorical exemptions: the Public Entity Exemption and the RPS Exemption. The details of each of these categorical exemptions are discussed in sections III.D.4 and 5 below.

2. *Process for Support and Review of Certification as Capacity Resource with Actionable Subsidy*

PJM is proposing generally the same “self-certification” process for sellers to inform PJM whether their resources qualify as a Capacity Resource with Actionable Subsidy as PJM is proposing for Capacity Repricing.²⁵² This approach recognizes that each seller knows best whether it receives a Material Subsidy in connection with any of its Generation Capacity Resources and whether the seller has obtained a categorical

²⁵² Compare proposed PJM Tariff, Attachment DD § 5.14(h)(3)(b) (Option B), with *id.*, Attachment DD § 5.14(j)(3)(b) (Option A).

exemption. Thus, each seller “must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy in accordance with Tariff, Attachment DD, section 5.14(h)(2), and if not, the officer must certify as to which criteria does not apply to the Capacity Resource.”²⁵³

In support of the certification, the seller must provide PJM and the IMM with “information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy.”²⁵⁴ The proposed MOPR-Ex rules lay out the deadlines and procedures for the provision of such information and allow PJM and the IMM to request additional information.²⁵⁵

As with the Capacity Repricing proposal, resources deemed to be a Capacity Resource with Actionable Subsidy shall continue to be considered a Capacity Resource with Actionable Subsidy “unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status pursuant to [a PJM determination of fraud or material misrepresentation], or by Commission order.”²⁵⁶ And, sellers will have a continuing obligation to notify PJM and the IMM of any material changes in the qualifications of the resource.²⁵⁷

3. *Revised MOPR Floor Offer Price to Cover Generation Resources of All Fuel Types*

Given that the MOPR-Ex proposal will expand offer price mitigation to generation resources of all fuel types, PJM is proposing that the MOPR Floor Offer Price

²⁵³ See proposed PJM Tariff, Attachment DD § 5.14(h)(3)(b) (Option B).

²⁵⁴ See proposed PJM Tariff, Attachment DD § 5.14(h)(3)(a) (Option B).

²⁵⁵ See proposed PJM Tariff, Attachment DD § 5.14(h)(3)(a) (Option B).

²⁵⁶ See proposed PJM Tariff, Attachment DD § 5.14(h)(3)(c) (Option B).

²⁵⁷ *Id.*

will no longer be based on specified Net Asset Class CONE values. Rather, the MOPR Floor Offer Price

shall be the product of the Net Cost of New Entry (applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered) times the average of the Balancing Ratios during the Performance Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year.²⁵⁸

In other words, the MOPR Floor Offer Price will be the Market Seller Offer Cap for the LDA in which the resource is offered. The Commission has found that an offer at the Market Seller Offer Cap (i.e., Net CONE*B) is “a reasonable estimate of a low-end competitive offer, after accounting for all marginal costs, opportunity costs, and risks associated with assuming a Capacity Performance commitment.”²⁵⁹ Setting the MOPR Floor Offer Price at a level the Commission has already held to represent a competitive offer is reasonable.

4. *As Part of MOPR-Ex, PJM Is Re-proposing the Categorical Exemptions Plus Retention of the Unit-Specific Exception Approach the Commission Found to Be Just and Reasonable in Docket No. ER13-535*

Because the MOPR-Ex proposal was developed prior to the Commission’s remand rejection of the MOPR provisions in Docket No. ER13-535, the MOPR-Ex proposal generally builds on the MOPR package that the Commission found to be just and reasonable and that was in place for the past seven years of RPM Auctions.²⁶⁰ That

²⁵⁸ See proposed PJM Tariff, Attachment DD § 5.14(h)(4) (Option B).

²⁵⁹ *PJM Interconnection, L.L.C.* 155 FERC ¶ 61,157, at P 184 (2016) (citing *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 336 (“The default offer cap that PJM proposes as part of its Revised Offer Cap reflects the amount that a competitive resource with low avoidable costs . . . would accept in the capacity market.”)).

²⁶⁰ See generally May 2013 Order and October 2015 Order.

MOPR allowed sellers to offer below the MOPR Floor Offer Price by obtaining a Unit-Specific Exception or to avoid offer price mitigation by obtaining one of two categorical exemptions: Self-Supply Exemption and Competitive Entry Exemption.

As discussed, in the MOPR-Ex proposal, PJM is revising the MOPR to include both a Unit-Specific Exception and categorical exemptions. By so proposing, MOPR-Ex addresses the Commission's fundamental issue with the MOPR revisions it rejected, without prejudice, on remand in Docket No. ER13-535. As a result, the Commission's findings that the Self-Supply and Competitive Entry Exemptions, as packaged with the Unit-Specific Exception, are just and reasonable should continue to apply. The Commission found that "[b]oth exemptions are structured to exempt resources of entities that lack the incentive or ability to suppress prices."²⁶¹

a. PJM Is Re-Proposing the Self-Supply and Competitive Entry Exemptions with Minimal Changes

The Self-Supply Exemption, which focuses on the characteristics of the Capacity Market Seller, allowed any new resource offered by such a seller to be exempt from the MOPR. The Commission found "that, as a general matter, providing exemptions for resources properly designated as self-supply when they meet suitable net-short and net-long thresholds is reasonable."²⁶² The MOPR-Ex proposals minimal changes to the Self-

²⁶¹ October 2015 Order at P 36.

²⁶² May 2013 Order at P 108; *see also* October 2015 Order at P 35 ("In traditionally-regulated states, a large majority of load is typically satisfied by generation owned by the load serving entity and recovered through state cost of service rates. Because of this financing model, the competitive entry exemption is not applicable to resources developed through that model. PJM, therefore, appropriately developed the self-supply exemption to determine under this financing model whether an investment in new generation is consistent with a competitive market.").

Supply Exemption and includes the net long and net short thresholds.²⁶³ The proposed MOPR-Ex modifications to the Self-Supply Exemption only serve to expand it to existing resources and to remove the provisions specific to the entities that will now be covered by the new Public Entity Exemption.²⁶⁴ Accordingly, the Self-Supply Exemption is just and reasonable, as the Commission previously held.

The Competitive Entry Exemption exempted from the MOPR resources for which the seller either receives no out-of-market state subsidy or, if so, was selected for such subsidy through a competitive and non-discriminatory state procurement process.²⁶⁵ The Commission has found that “PJM’s proposed categorical exemption for competitive-entry, subject to conditions, as a just and reasonable modification to PJM’s MOPR process. We agree with PJM that this proposed exemption will remove an unnecessary barrier to entry for merchant projects and other projects that are procured on a competitive basis.”²⁶⁶ As the Commission has correctly described:

A resource can obtain a competitive entry exemption in either of two ways. The first is to show that one hundred percent of the revenues such investment earns must be derived by meeting

²⁶³ See proposed PJM Tariff, Attachment DD § 5.14(h)(7) (Option B).

²⁶⁴ See proposed PJM Tariff, Attachment DD §§ 5.14(h)(5)(i) (removing language specific to “Public Power Entities”), 5.14(h)(5)(iii) (same), 5.14(h)(5)(vii) (removing definition of “Municipal/Cooperative Entity”) (Option B). In addition to those changes to the previously-accepted Self-Supply Exemption required to accommodate the new Public Entity Exemption, PJM is proposing that the officer certification requirement that was in the prior Self-Supply Exemption be moved to the Exemption/Exception Process section to prevent unnecessary duplication in the tariff. Section (c) of the Exemption/Exception Process section provides for a generic officer certification applicable to all the categorical exemptions and the unit-specific exception process. See proposed PJM Tariff, Attachment DD § 5.14(h)(11)(c) (Option B).

²⁶⁵ PJM Tariff, Attachment DD § 5.14(h)(6) (language in effect prior to Remand Order).

²⁶⁶ May 2013 Order at P 53.

market demand for energy, capacity, and ancillary services; and that no revenues are earned by non-by-passable charges to ratepayers. The second way is to show that any contractual revenues received by the resource are as a result of a nondiscriminatory procurement process that is competitive and open to all resources, including existing resources. Subjecting investment that meets either of these conditions to any buyer-side market power mitigation that could penalize its entry does not enhance competition because in either case, competitive forces are a sufficient protection against uneconomic entry.²⁶⁷

In MOPR-Ex, PJM is proposing *no substantive changes* to the Competitive Entry Exemption the Commission accepted in Docket No. ER13-535. PJM is only proposing to remove “Entry” from its name (i.e., “Competitive Exemption”) to reflect that the new MOPR rules cover existing resources in addition to new entry,²⁶⁸ and to move the officer certification requirement to the general Exemption/Exception Process section,²⁶⁹ in an effort to remove duplication from each of the exemptions and streamline the PJM Tariff.

b. PJM Is Proposing to Retain the Unit-Specific Exception and Update Its Rules to Cover Existing Resources

Because Capacity Resources with Actionable Subsidy may in fact have lower competitive costs, without consideration of the Material Subsidy, than the MOPR Offer

²⁶⁷ October 2015 Order at P 32.

²⁶⁸ Proposed PJM Tariff, Attachment DD § 5.14(h)(8) (Option B). PJM notes that by focusing the MOPR-Ex on only Capacity Resources with Actionable Subsidies, only resources that are receiving a Material Subsidy would be subject to MOPR-Ex, and that only resources that do *not* receive a Material Subsidy are eligible for a Competitive Exemption. In other words, any resource that would qualify for a Competitive Exemption would not be a Capacity Resource with Actionable Subsidy and would not be subject to MOPR-Ex. Nonetheless, PJM is proposing the Competitive Exemption because it was part of the MOPR-Ex proposal the stakeholders reviewed. But, given the internal inconsistency of the Competitive Exemption in the proposed MOPR-Ex, PJM is informing the Commission and all parties that to address the notice issues which were significant to the Court’s holding in *NRG*, PJM is willing to accept a Commission directive to remove the Competitive Exemption from any MOPR-Ex proposal the Commission accepts.

²⁶⁹ See proposed PJM Tariff, Attachment DD § 5.14(h)(11)(c) (Option B).

Floor Price, such “resources should have the opportunity to demonstrate their competitive entry costs.”²⁷⁰ Accordingly, PJM is proposing to retain the Unit-Specific Exception. However, the unit-specific exception rules must be updated to reflect the expansion to existing resources so that sellers may know what data they must provide to support such an exception from the MOPR-Ex. To this end, PJM is proposing to make clear that the existing unit-specific process applies to “new entry” and is adding a new provision for existing resources.²⁷¹

Under MOPR-Ex, sellers of existing resources “shall submit a Sell Offer equal to the higher of the Avoidable Cost Rate, as defined in 6.8(a), net of Projected PJM Market Revenues, and the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap.”²⁷² When determining the opportunity cost value, the seller must “employ[] alternative assumptions for the availability ratio (A), the number of Performance Assessment Hours (H), the Balancing Ratio (B), and the Capacity Performance bonus payment rate (CPBR) based on the actual market conditions and the actual circumstances of the unit.”²⁷³ This is identical to the competitive price determination PJM is proposing for its Capacity Repricing approach.²⁷⁴ As explained above, either the Avoidable Cost Rate or the opportunity cost value would be a competitive offer price for the resource and

²⁷⁰ May 2013 Order at P 141.

²⁷¹ See proposed PJM Tariff, Attachment DD § 5.14(h)(6)(c) (Option B).

²⁷² Proposed PJM Tariff, Attachment DD § 5.14(h)(6)(c) (Option B).

²⁷³ Proposed PJM Tariff, Attachment DD § 5.14(h)(6)(c) (Option B).

²⁷⁴ Compare proposed PJM Tariff, Attachment DD § 5.14(j)(4)(a) (Option A), with *id.*, Attachment DD § 5.14(h)(6)(c) (Option B).

selecting the “higher of” of these two values comports with the logic underlying the Market Seller Offer Cap.²⁷⁵

PJM is also re-prosing minor wording and structural changes to the unit-specific exception rules that the Commission accepted on compliance in Docket No. ER13-535.²⁷⁶ Plus, instead of cross-referencing Net Asset Class CONE estimates (which PJM is proposing to replace, see section III.D.3 above), PJM is proposing to list the financial modelling assumptions that a seller must provide to support a Unit-Specific Exception.²⁷⁷

5. *Two New Categorical Exemptions*

a. Public Entity Exemption

The Public Entity Exemption applies to two types of entities that were previously covered by the Self-Supply Exemption: Public Power Entity²⁷⁸ and Electric Cooperative.²⁷⁹ Like all other MOPR exemptions, this exemption allows resources from qualifying sellers to offer into RPM Auctions at any price selected by the seller, including a price of zero.

²⁷⁵ See Capacity Performance Order at PP 334-58; Capacity Performance Rehearing Order at PP 182-96.

²⁷⁶ June 2013 Compliance Filing at 3-5; *id.* at Attachment B (clean tariff sheets); October 2015 Order at P 107.

²⁷⁷ See proposed PJM Tariff, Attachment DD § 5.14(h)(6)(b) (Option B).

²⁷⁸ A Public Power Entity is “any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.” RAA, Article 1.

²⁷⁹ An Electric Cooperative is “an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.” RAA, Article 1.

The Public Entity Exemption applies much of the same qualifying criteria as the Self-Supply Exemption, in particular: a net long threshold,²⁸⁰ and cost and revenue requirements.²⁸¹ A net long threshold addresses the concern that an LSE may have such a relatively large amount of excess capacity that it may seek to “dump” capacity on the RPM auction, pushing down capacity prices in the process. The net long requirement under the Public Entity Exemption is proposed to be 600 MW.²⁸² That is, to qualify for the exemption, a Public Power Entity or an Electric Cooperative must not own or have under its control more than 600 MW of unforced capacity in excess of its Estimated Capacity Obligation for the PJM Region. This 600 MW value is consistent with the net long threshold test the Commission initially accepted in Docket No. ER13-535.²⁸³ There, for entities with a capacity obligation “Greater than or equal to 500 and less than 5,000,” the entities maximum net long position is “15% of LSE’s Estimated Capacity Obligation.”²⁸⁴ Given that most Public Power Entities and Electric Cooperatives have capacity obligations of less than 5,000 MW, selecting a value that is equal to 15% of 4,000 (i.e., 600 MW) is reasonable.

Unlike the Self-Supply Exemption, to qualify for a Public Entity Exemption, sellers do not have to meet a stated net short threshold. Rather, to qualify for this exemption, a Public Power Entity or an Electric Cooperative must have “long-term

²⁸⁰ Compare proposed PJM Tariff, Attachment DD § 5.14(h)(5)(d), with *id.*, Attachment DD § 5.14(h)(9)(b) (Option B).

²⁸¹ Compare proposed PJM Tariff, Attachment DD § 5.14(h)(5)(a), with *id.*, Attachment DD § 5.14(h)(9)(c) (Option B).

²⁸² See proposed PJM Tariff, Attachment DD § 5.14(h)(9)(b) (Option B).

²⁸³ June 2013 Compliance Filing at Attachment B (proposed PJM Tariff, Attachment DD § 5.14(h)(6)(iv)).

²⁸⁴ *Id.*

resource plans” for the capacity under its control that is “consistent with its business model and such resource plans are intended to be balanced with its load obligations.”²⁸⁵ In other words, over the entity’s long-term planning horizon, the entity must plan on having under its control a quantity of capacity resources that is “planned to be less than or equal to” its retail load capacity obligations.²⁸⁶

Finally, to reflect that application of the net long test to a portfolio of existing resources, the proposed Public Entity Exemption includes the following provision:

Any excess supply, starting with the Capacity Resource(s) most recently added to the portfolio, will be subject to the Minimum Offer Price Rule unless the Capacity Resource qualifies for a Unit-Specific Exception under Tariff, Attachment DD, section 5.14(h)(6), where excess supply is the MW amount of Owned and Contracted Capacity in excess of the sum of LSE Total Estimated Capacity Obligation and 600 MW. The Minimum Offer Price Rule or Unit-Specific Exception shall apply to the last unit(s) added to Owned and Contracted Capacity.²⁸⁷

This provision reasonably provides that the MOPR will apply to the resources that took the seller beyond the net long threshold and to any resources that the seller acquired (whether bought or constructed) after the seller had crossed that threshold.²⁸⁸

²⁸⁵ See proposed PJM Tariff, Attachment DD § 5.14(h)(9)(a) (Option B).

²⁸⁶ See proposed PJM Tariff, Attachment DD § 5.14(h)(9)(a) (Option B).

²⁸⁷ Proposed PJM Tariff, Attachment DD § 5.14(h)(9)(c) (Option B).

²⁸⁸ The Capacity Repricing proposal does not include a net-long requirement for Municipal/Cooperative Entities while the MOPR-Ex does include one. Both are just and reasonable approaches given the goals of each proposal. That is Capacity Repricing’s goal is to ensure a Capacity Resource with Actionable Subsidy is allowed to obtain a commitment and then it is repriced to a competitive price (the Actionable Subsidy Reference Price), whereas the goal of MOPR-Ex is to prevent uncompetitive offers from clearing the market at all. Thus either approach can be found just and reasonable.

b. RPS Exemption

The other new categorical exemption from the MOPR is for resources that receive out-of-market support as part of a state-sponsored renewable portfolio standard. The RPS Exemption represents one discrete aspect of an overall just and reasonable approach to addressing the issue of the impact of increasing state subsidization of units on the RPM clearing price. The RPS Exemption, as presented in this proposal, ensures that MOPR-Ex targets the mitigation action to the most recent state actions and targets those state actions which are clearly focused on affecting the competitive position of specific units in the market.

Capacity Market Sellers may qualify resources for the RPS Exemption under one of two scenarios. Both scenarios are broadly stated and accommodate most state RPS programs. First, resources that were “procured in a program in compliance with a state mandated renewable portfolio standard prior to December 31, 2018, or based on a request for proposals (RFP) issued under such program prior to December 31, 2018” will qualify for the exemption.²⁸⁹ This criterion ensures that any seller expectations leading to its RPS procurement will not be upset. This is a reasonable transition as such commitments were likely made based on RPM’s longstanding practice of applying the MOPR to only gas-fired generation resources and not to renewable resources and sellers had no knowledge or expectation of any contemplated expansion of MOPR to other resource types.

Under the second path, resources that do not meet that criterion may qualify for the RPS Exemption if the resource “complies with the requirements of a state-mandated

²⁸⁹ Proposed PJM Tariff, Attachment DD § 5.14(h)(10)(a) (Option B).

renewable portfolio standard or voluntary renewable portfolio standard”²⁹⁰ and the terms of such program terms are “competitive and non-discriminatory.”²⁹¹ If a resource is procured as part of an RPS program through an auction, that auction “must be competitive and non-discriminatory, meaning “(1) winner(s) of auction based on lowest offer prices, (2) payments to winners based on auction clearing price, and (3) at least three non-affiliated sellers participate.”²⁹² On the other hand, if the resource is not procured through an auction (i.e., like renewable energy credits), the terms of procurement must “(1) [be] consistent with fair market value and standard industry practice and (2) provide that the price paid for renewable energy credits is determined by the contract terms between the buyer and the seller.”²⁹³

The criteria proposed under this second path allows sales of unbundled RECs to be exempt from the MOPR-Ex. In other words, if a resource owner sells RECs based on that resource to an LSE participating a state-sponsored RPS program, then that resource can obtain an RPS Exemption and would not be subject to the MOPR-Ex. This is true whether the RECs from the resource are sold bilaterally (at fair market value) or through an auction process, so long as RPS Exemption’s stated criteria for such a sale and for the state-sponsored RPS program are met.

²⁹⁰ Proposed PJM Tariff, Attachment DD § 5.14(h)(10)(b)(i) (Option B).

²⁹¹ Proposed PJM Tariff, Attachment DD § 5.14(h)(10)(b)(ii) (Option B). PJM is proposing seven criteria that a state program must meet to be considered “competitive and non-discriminatory,” including that the “program terms do not use any locational requirement, e.g. offshore wind, other than restricting imports from other states.” *Id.*

²⁹² Proposed PJM Tariff, Attachment DD § 5.14(h)(10)(b)(iv) (Option B).

²⁹³ Proposed PJM Tariff, Attachment DD § 5.14(h)(10)(b)(iii) (Option B).

- i. *Notice under Federal Power Act section 205 that PJM is willing to accept a MOPR-Ex proposal that does not include an RPS Exemption*

Given that this RPS Exemption allows resources receiving out-of-market subsidies to escape mitigation in deference to public policies favoring renewable generation resources, not because such resources do not suppress prices, some parties may assert that this rule discriminates in favor of resources versus other types of subsidized generation resources. Whether or not this form of discrimination is undue, in light of the CASPR Order, is a decision for this Commission. PJM offers the option of either (i) applying the standards set forth in Capacity Repricing to govern the treatment of renewables, or (ii) identifying this question for further stakeholder consideration in subsequent processes. PJM believes that this affirmative notice satisfies FPA section 205's notice requirements, as explained by the *NRG* court.

6. *PJM Is Re-Proposing Other Categorical Exemption-Related MOPR Revisions Accepted in Docket No. ER13-535*

The proposed MOPR-Ex rules re-propose the provision accepted in Docket No. ER13-535²⁹⁴ that makes explicit that when a resource obtains any exemption, the market seller may offer the resource at a price below the MOPR floor price, "including, without limitation, an offer price of zero or other indication of intent to clear regardless of price."²⁹⁵ This provision simply states the common understanding of the effect of an exemption from the MOPR Floor Offer Price. PJM is also updating the provision to reference the tariff sections for such exemptions instead of listing them by name.²⁹⁶

²⁹⁴ June 2013 Compliance Filing at Attachment B (proposed PJM Tariff, Attachment DD § 5.14(h)(5)).

²⁹⁵ Proposed PJM Tariff, Attachment DD § 5.14(h)(5) (Option B).

²⁹⁶ Proposed PJM Tariff, Attachment DD § 5.14(h)(5) (Option B).

To implement the categorical exemptions and unit-specific exception, PJM is re-proposing the “Exemption/Exception Process” section the Commission accepted in the Docket No. ER13-535 proceeding.²⁹⁷ This section provides the deadlines for the various steps in the exemption and exception processes that are designed to produce a final PJM decision on the request sufficiently in advance of the relevant auction to allow the seller an opportunity to pursue any relief it deems appropriate.²⁹⁸ PJM is proposing one change to the Exemption/Exception Process provisions—to add a generic seller certification provision here, rather than including ones specific to each exemption and the unit-specific exception.²⁹⁹ This change removes duplication in the already very long MOPR rules while maintaining the requirement that a seller must certify that its resource meets the requirement of the exemption/exception requested.

MOPR-Ex also carries forward from Docket No. ER13-535³⁰⁰ the safeguard provisions to address the consequences if PJM reasonably believes that a previously granted request for a categorical exemption contains or is based on fraudulent or material misrepresentations or omissions and, absent such misrepresentations or omissions, would not have been eligible for the exemption.³⁰¹

To properly implement MOPR-Ex, PJM is also making conforming changes to Tariff, Attachment M-Appendix, section II.D to re-propose the procedures and deadlines

²⁹⁷ MOPR Tariff Filing of PJM Interconnection, L.L.C., Docket No. ER13-535-000, at 21 (Dec. 7, 2012); June 2013 Compliance Filing at Attachment A (proposed PJM Tariff, Attachment DD § 5.14(h)(9)) that inserted “exceptions” into the provision); October 2015 Order at P 107.

²⁹⁸ Proposed PJM Tariff, Attachment DD § 5.14(h)(11) (Option B).

²⁹⁹ Proposed PJM Tariff, Attachment DD § 5.14(h)(11)(c) (Option B).

³⁰⁰ See May 2013 Order at P 115.

³⁰¹ See proposed PJM Tariff, Attachment DD § 5.14(h)(12) (Option B).

for the IMM's review of exemption and exception requests that the Commission accepted in Docket No. ER13-535.³⁰²

Finally, PJM is re-proposing RPM Auction posting requirements that enhance transparency in application of the MOPR and notify market participants of the aggregate megawatt quantity of resources granted for each categorical exemptions³⁰³ as well as the aggregate megawatt quantity that cleared a BRA for each exemption.³⁰⁴ In addition, PJM is re-proposing that PJM will provide notice to market participants prior to the BRA when it has made a generic determination that a particular state procurement process is "Competitive and Non-Discriminatory."

IV. EFFECTIVE DATE AND REQUEST FOR WAIVER

As stated above, PJM proposes an effective date of January 4, 2019, for the accompanying Tariff revisions, and for that purpose requests waiver of the Commission's 120-day maximum notice rule.³⁰⁵ However, PJM also asks the Commission to issue an Order on this filing by June 29, 2018. To that end, PJM has assigned an effective date of June 30, 2018, to one revised tariff record in both Option A and Option B.³⁰⁶ Based on PJM's showings in this filing, the Commission has substantial evidence on which it could fully accept either of the two alternatives in an order issued by June 29, 2018.

³⁰² See proposed PJM Tariff, Attachment M-Appendix § II.D (Option B).

³⁰³ See proposed PJM Tariff, Attachment DD § 5.11(b) (Option B).

³⁰⁴ See proposed PJM Tariff, Attachment DD § 5.11(f) (Option B).

³⁰⁵ See 18 C.F.R. § 35.3(a)(1). Waiver is warranted here, given that PJM proposes that these revisions will have their first application to the May 2019 Base Residual Auction. Given this filing's significance, PJM is filing it well before that auction.

³⁰⁶ Specifically, PJM has assigned an effective date of June 30, 2018, to the Attachment DD title tariff record. No substantive changes are being made to this section.

V. CORRESPONDENCE

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

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

Paul M. Flynn
Ryan J. Collins
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200 (phone)
(202) 393-1240 (fax)
flynn@wrightlaw.com
collins@wrightlaw.com

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

Chenchao Lu
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-2255 (phone)
(610) 666-8211 (fax)
Chenchao.Lu@pjm.com

VI. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;
2. Option A: Revisions to the PJM Tariff in redlined as Attachment A in electronic tariff filing format as required by Order No. 714;
3. Option A: Revisions to the PJM Tariff in non-redlined format Attachment B in electronic tariff filing format as required by Order No. 714;
4. Option B: Revisions to the PJM Tariff in redlined as Attachment C in electronic tariff filing format as required by Order No. 714;
5. Option B: Revisions to the PJM Tariff in non-redlined format Attachment D in electronic tariff filing format as required by Order No. 714;
6. Affidavit of Adam J. Keech on Behalf of PJM, as Attachment E; and
7. Affidavit of Dr. Anthony Giacomoni on Behalf of PJM, as Attachment F.

VII. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,³⁰⁷ 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 Region³⁰⁸ 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.

³⁰⁷ See 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

³⁰⁸ PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

VIII. CONCLUSION

Accordingly, PJM requests that the Commission accept either the enclosed Tariff revisions under Option A or Option B, and reject the unaccepted Tariff revisions, as moot.

Respectfully submitted,

/s/ Paul M. Flynn

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

Paul M. Flynn
Ryan J. Collins
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200 (phone)
(202) 393-1240 (fax)
flynn@wrightlaw.com
collins@wrightlaw.com

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

Chenchao Lu
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-2255 (phone)
(610) 666-8211 (fax)
Chenchao.Lu@pjm.com

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Attachment A

Revisions to the PJM Open Access Transmission Tariff

Option A

(Marked/Redline Format)

Definitions – A - B**Abnormal Condition:**

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

Acceleration Request:

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

Actionable Subsidy Reference Price:

“Actionable Subsidy Reference Price” shall have the meaning provided in Tariff, Attachment DD, section 5.14(j).

Additional Day-ahead Scheduling Reserves Requirement:

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

Affected System:

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

Affected System Operator:

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

Affiliate:

“Affiliate” shall mean any two or more entities, one of which controls the other or that are under common control. “Control” shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

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

Ancillary Services:

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

Annual Demand Resource:

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

Annual Energy Efficiency Resource:

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

Annual Resource:

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

Annual Resource Price Adder:

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

Annual Revenue Rate:

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

Annual Transmission Costs:

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

Applicable Laws and Regulations:

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

Applicable Regional Entity:

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

Applicable Standards:

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

Applicable Technical Requirements and Standards:

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

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, or to take Transmission

Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

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

Attachment Facilities:

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

Attachment H:

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

Auction Revenue Rights:

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

Auction Revenue Rights Credits:

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

Authorized Government Agency:

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

Avoidable Cost Rate:

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

Balancing Congestion Charges:

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

Balancing Ratio:

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

Base Capacity Demand Resource:

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

Base Capacity Demand Resource Constraint:

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

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a

percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

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

Base Capacity Energy Efficiency Resource:

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

Base Capacity Resource:

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

Base Capacity Resource Constraint:

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

for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

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

Base Capacity Resource Price Decrement:

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

Base Day-ahead Scheduling Reserves Requirement:

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

Base Load Generation Resource

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

Base Offer Segment:

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

Base Residual Auction:

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

Batch Load Demand Resource:

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

Behind The Meter Generation:

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

Black Start Service:

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

Breach:

“Breach” shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

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

Business Day:

“Business Day” shall mean a day in which the Federal Reserve System is open for business and

is not a scheduled PJM holiday.

Buy Bid:

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

Definitions – C-D

Canadian Guaranty:

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

Cancellation Costs:

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

Capacity:

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

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

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

Capacity Import Limit:

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

Capacity Interconnection Rights:

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

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

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

Capacity Performance Transition Incremental Auction:

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

Capacity Resource:

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

Capacity Resource Clearing Price:

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

Capacity Resource with Actionable Subsidy:

“Capacity Resource with Actionable Subsidy” or “Capacity Resources with Actionable Subsidies” shall have the meaning provided in Tariff, Attachment DD, section 5.14(j).

Capacity Storage Resource:

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

Capacity Transfer Right:

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

Capacity Transmission Injection Rights:

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

Cold/Warm/Hot Notification Time:

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

Cold/Warm/Hot Start-up Time:

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

Cold Weather Alert:

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

Collateral:

“Collateral” shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

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

Commencement Date:

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

Commission:

“Commission” shall mean the Federal Energy Regulatory Commission or FERC.

Committed Offer:

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

Completed Application:

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

Compliance Aggregation Area (CAA):

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

Incremental Auction, the same locational price separation in the Third Incremental Auction, *or the same locational price separation in the Final Incremental Auction.*

Conditional Incremental Auction:

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

CONE Area:

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

Confidential Information:

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

Congestion Price:

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

Consolidated Transmission Owners Agreement:

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

Constructing Entity:

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

Construction Party:

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

Construction Service Agreement:

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

Control Area:

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

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

Control Zone:

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

Controllable A.C. Merchant Transmission Facilities:

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

Coordinated External Transaction:

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

Coordinated Transaction Scheduling:

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

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:

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

Costs:

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

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own .

Credit Available for Export Transactions:

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

Credit Available for Virtual Transactions:

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

Credit Breach:

“Credit Breach” shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:

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

Credit Score:

“Credit Score” shall mean a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:

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

CTS Interface Bid:

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

Curtailement:

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

Curtailment Service Provider:

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

Customer Facility:

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

Customer-Funded Upgrade:

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

Customer Interconnection Facilities:

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

Daily Deficiency Rate:

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

Daily Unforced Capacity Obligation:

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

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

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

Day-ahead Energy Market Injection Congestion Credits:

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

Day-ahead Energy Market Transmission Congestion Charges:

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

Day-ahead Energy Market Withdrawal Congestion Charges:

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

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-ahead Scheduling Reserves:

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

Day-ahead Scheduling Reserves Market:

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

Day-ahead Scheduling Reserves Requirement:

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

Day-ahead Scheduling Reserves Resources:

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

Day-ahead Settlement Interval:

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

Day-ahead System Energy Price:

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

Deactivation:

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

Deactivation Avoidable Cost Credit:

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

Deactivation Avoidable Cost Rate:

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

Deactivation Date:

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

Decrement Bid:

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

Default:

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

Delivering Party:

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

Delivery Year:

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

Demand Bid:

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

Demand Bid Limit:

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

Demand Bid Screening:

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

Demand Resource:

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

Demand Resource Factor or DR Factor:

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

Designated Agent:

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

Designated Entity:

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

Direct Assignment Facilities:

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

Direct Load Control:

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

Dispatch Rate:

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

Dynamic Schedule:

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

Dynamic Transfer:

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

Definitions – L – M - N

Limited Demand Resource:

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

Limited Demand Resource Reliability Target:

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

Limited Resource Constraint:

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

Limited Resource Price Decrement:

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

List of Approved Contractors:

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

Load Management:

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

Load Management Event:

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

Load Ratio Share:

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

Load Reduction Event:

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

Load Serving Entity (LSE):

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

Load Shedding:

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

Local Upgrades:

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

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

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

Location:

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

LOC Deviation:

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

unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

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

Locational Deliverability Area Reliability Requirement:

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

Locational Price Adder:

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

Locational Reliability Charge:

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

Locational UCAP:

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

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

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

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

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

Loss Price:

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

Maintenance Adder:

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

Manual Load Dump Action:

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

Manual Load Dump Warning:

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

Market Monitor:

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

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the organization that is responsible for implementing this Plan, including the Market Monitor.

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

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

Market Operations Center:

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

Market Participant:

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

Market Participant Energy Injection:

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

Market Participant Energy Withdrawal:

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

Market Seller Offer Cap:

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

Market Violation:

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

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any

Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Material Subsidy:

“Material Subsidy” shall mean: (1) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource. A Material Subsidy shall not include (3) 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; (4) 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 (5) 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.

Maximum Daily Starts:

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

Maximum Emergency:

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

Maximum Facility Output:

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

Maximum Generation Emergency:

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

Maximum Generation Emergency Alert:

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

Maximum Run Time:

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

Maximum Weekly Starts:

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

Member:

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

Merchant A.C. Transmission Facilities:

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

Merchant D.C. Transmission Facilities:

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

Merchant Network Upgrades:

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

Merchant Transmission Facilities:

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

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Section 36 of the Tariff, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

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

Minimum Annual Resource Requirement:

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

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and

unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

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

Minimum Generation Emergency:

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

Minimum Participation Requirements:

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

Minimum Run Time:

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

MISO:

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

Multi-Driver Project:

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

Native Load Customers:

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

NERC:

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

NERC Interchange Distribution Calculator:

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

Net Benefits Test:

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

Net Cost of New Entry:

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

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts Part II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be

formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

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

Network Customer:

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

Network External Designated Transmission Service:

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

Network Integration Transmission Service:

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

Network Load:

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

Network Operating Agreement:

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

Network Operating Committee:

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

Network Resource:

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

Network Service User:

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

Network Transmission Service:

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

Network Upgrades:

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

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

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

Neutral Party:

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

New PJM Zone(s):

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

New Service Customers:

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

New Service Request:

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

New Services Queue:

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

New Services Queue Closing Date:

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the *six*-month period ending on such date.

New York ISO or NYISO:

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

Nodal Reference Price:

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

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as

determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

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

Nominated Energy Efficiency Value:

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

Non-Firm Point-To-Point Transmission Service:

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

Non-Firm Sale:

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

Non-Firm Transmission Withdrawal Rights:

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

Non-Performance Charge:

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

Nonincumbent Developer:

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

Non-Regulatory Opportunity Cost:

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

Non-Retail Behind The Meter Generation:

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

Non-Synchronized Reserve:

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

Non-Synchronized Reserve Event:

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

Non-Variable Loads:

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

Non-Zone Network Load:

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

Normal Maximum Generation:

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

Normal Minimum Generation:

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

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this Section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting

forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this Section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Section 18.17 of the PJM Operating Agreement.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of Section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this Section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the PJM Market Monitor using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the PJM Market Monitor from a third party which is not, to the Office of the Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this Section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. Disclosure to FERC and CFTC:

1. Notwithstanding anything in this Section I to the contrary, if the FERC, the Commodity Futures Trading Commission (“CFTC”) or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing Section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC’s Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in Section I.B.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this Section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Schedule 10A. Upon receipt of the Authorized Commission’s Certification, the FERC shall provide public notice of the Authorized Commission’s filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission’s Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC’s consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission’s Certification within 90 days of the date of filing, the Certification shall be deemed approved and the

Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this Section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided

however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of Section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding Section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds

for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this Section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this Section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this Section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not

act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in Section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in Section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. Market Monitoring:

1. Subject to the requirements of Section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that the Office of the Interconnection or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of the Office of the Interconnection and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member's confidential information pursuant to Section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure

specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under Section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this Section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.
2. The Market Monitoring Unit shall review the incremental costs (defined in Section 6.4.2 of Schedule 1 of the Operating Agreement) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Schedule 2 of the Operating Agreement.
3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Section 6.4.2 of Schedule 1 of the Operating Agreement is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.
4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Section 6.4 of Schedule 1 of the Operating Agreement. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.
5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. Minimum Generator Operating Parameters:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Section 6.6(c) of Schedule 1 of the Operating Agreement. The Parameter Limited Schedule Matrix shall include

default values on a unit-type basis as specified in Section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Section 6.6 of Schedule 1 of the Operating Agreement and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Section 6.6 of Attachment DD.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to Section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation

Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORD to be included in a Sell Offer applicable to each resource pursuant to Section 6.6(b) of Attachment DD. If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORD to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORD if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Section 5.6.6 of Attachment DD of the PJM Tariff, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in Section II.C.4 above, or (iii) a maximum EFORD that the Market Monitoring Unit believes is inconsistent with the maximum level determined under Section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Section 6.6 of Attachment DD.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Section 6.6 of Attachment DD, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Section 6.6(g) of Attachment DD, to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Section 6.6(i) of Attachment DD, and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. Repricing Sell Offers for Capacity Resources with Actionable Subsidy Unit Specific Minimum Sell Offers:

1. ~~Each~~^{If a} Capacity Market Seller ~~that timely~~ submits documentation for the determination an Actionable Subsidy Reference Price pursuant to the requirements set forth in Tariff, an exception request under Section 5.14(h) of Attachment DD, section 5.14(j)(4) with all of the required supporting documentation as, the Market Monitoring Unit shall review the ~~request and~~ documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ~~ninety-fourty-five~~ (9045) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer the Market

Monitoring Unit's determination of whether the requested Actionable Subsidy Reference Price is acceptable~~(a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.~~

2. All ~~data~~ information submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

D-1. Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy:

1. In the event that the Market Monitoring Unit reasonably believes that a certification of a Capacity Resource's status contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource would be a Capacity Resource with Actionable Subsidy had the certification not contained such misrepresentations or omissions, then it shall notify the Office of the Interconnection and Capacity Market Seller of its findings and provide the Office of the Interconnection with all of the data and documentation supporting its findings, and may take any other action required or permitted under Tariff, Attachment M.

E. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Section 6.7(d) of Attachment DD, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Section 6.4(a) of Attachment DD.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. Data Submission:

Pursuant to Section 6.7 of Attachment DD, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Section 6.7(c) of Attachment DD and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Section 6.7 of Attachment DD, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in section 6.7(d) of Attachment DD.

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Section 6.8(d) of Attachment DD, and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Section 6.7(d)(ii) of Attachment DD. The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Schedule 6A of the PJM Tariff and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Part V of the PJM Tariff from the Office of the Interconnection forwarded pursuant to Section 113.1 of the PJM Tariff, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power

impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Sections 114 and 119 of Part V of the PJM Tariff.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement, discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement.

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Section 5.2.1(b) of Schedule 1 of the Operating Agreement, including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in

the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the ~~repricing provisions of section 5.14(j) minimum offer price rule set forth in section 5.14(h)~~. Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, *Final* and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORD values for such Generation Capacity Resources prior to the conduct of the Third *Incremental Auction and Final* Incremental Auction, *as applicable*, for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity of Capacity Resources with Actionable Subsidies; the aggregate megawatt quantity cleared in the RPM Auction of Capacity Resources with Actionable Subsidies; and the aggregate megawatt quantity of Capacity Resources with Actionable Subsidies for any LDA other than those specified in the preceding clause if the LDA has four (4) or more generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth

above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm; provided, however, for each RPM Base Residual Auction conducted for the 2022/2023 Delivery Year and subsequent Delivery Years, once the optimization algorithm clears in any Delivery Year, for the PJM Region, more than 5,000 megawatts of unforced capacity from Capacity Resources with Actionable Subsidy, or for any modeled LDA, a megawatt quantity of Capacity Resources with Actionable Subsidy equal to or exceeding 3.5 percent of that LDA's Reliability Requirement, then the Capacity Resource Clearing Prices for the PJM Region will be determined in accordance with subsection 5.14(j).- 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.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

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. If the Sell Offer

price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

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

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.
2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.
3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORD).
4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

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

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

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

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a

separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

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

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. 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 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. 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) ~~[Reserved for Future Use] Minimum Offer Price Rule for Certain Generation Capacity Resources~~

~~(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment.~~

~~The gross Cost of New Entry component of 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”), and a combined cycle generator (“CC”) respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) 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) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.~~

| | 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 |

~~—— (2) — Beginning 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.~~

~~—— (3) — 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 CC 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.~~

~~(4) — Any Sell Offer that is based on:~~

~~i) — a Generation Capacity Resource located in the PJM Region that is submitted in an RPM Auction for a Delivery Year unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM auction for that or any subsequent Delivery Year; or~~

~~ii) — a Generation Capacity Resource located outside the PJM Region (where such Sell Offer is based solely on such resource) that requires sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region, unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior~~

~~Delivery Year, or until a Sell offer based on that resource clears an RPM Auction for that or any subsequent Delivery Year, in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.~~

~~(5)——Unit Specific Exception. A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection 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 process and requirements shall apply to requests for such determinations:~~

~~i)——The Capacity Market Seller may request such a determination by no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, 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 the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the minimum offer level expected to be established under subsection (4). If the minimum offer level 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 planned 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 an 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. 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 Minimum Offer Price Rule exception request.~~

~~iii) — A Sell Offer evaluated hereunder 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 minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), 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 estimated for subsection (4). 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 an exception hereunder by the Office of the Interconnection.~~

~~iv) — The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the~~

~~Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, 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 to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction~~

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.

j) Repricing to Accommodate Capacity Resources with Actionable Subsidies.

(1) General Rule.

(a) Once the optimization algorithm clears a quantity of Capacity Resources with Actionable Subsidies that is equal to or greater than 5,000 megawatts of unforced capacity for the entire PJM Region in a Base Residual Auction for any Delivery Year, to determine the Capacity Resource Clearing Prices for all Capacity Resources for such Delivery Year and all subsequent Delivery Years, as adjusted as necessary by any applicable Locational Price Adders, the Office of the Interconnection shall re-run the optimization algorithm using the same submitted Sell Offers, but for each Capacity Resource with Actionable Subsidy, the Office of the Interconnection shall apply an Actionable Subsidy Reference Price as determined in accordance with Tariff, Attachment DD, section 5.14(j)(4).

(b) If the initial optimization algorithm clears less than 5,000 megawatts of unforced capacity from Capacity Resources with Actionable Subsidies for the entire PJM Region, but the optimization algorithm clears a quantity of Capacity Resources with Actionable Subsidies that is equal to or greater than 3.5 percent of the Reliability Requirement for any modeled LDA, then, to determine the Capacity Resource Clearing Price for all Capacity Resources for such Delivery Year and all subsequent Delivery Years, as adjusted as necessary by any applicable Locational Price Adders, the Office of the Interconnection shall re-run the optimization algorithm using the same submitted Sell Offers, but for each Capacity Resource with an Actionable Subsidy in that modeled LDA, the Office of the Interconnection shall apply an Actionable Subsidy Reference Price as determined in accordance with Tariff, Attachment DD, section 5.14(j)(4).

(2) Capacity Resources with Actionable Subsidies.

A Capacity Resource that meets all of the following criteria shall be deemed to be a Capacity Resource with Actionable Subsidy:

(a) The Capacity Market Seller formally or informally, directly or indirectly, seeks, recovers, accepts or receives a Material Subsidy with regard to such Capacity Resource;

(b) The Capacity Resource is a Demand Resource or a Generation Capacity Resource or uprate, or planned uprate, to a Generation Capacity Resource that has an Unforced Capacity of 20 MW or greater;

(c) The Capacity Market Seller is a (i) Municipal/Cooperative Entity, which means cooperative and municipal utilities including public power supply entities comprised of either or both of the same, and joint action agencies, or a (ii) Vertically Integrated Utility, which 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) The Material Subsidy the Capacity Market Seller in any way receives for such Capacity Resource is greater than 1% of such Capacity Resource's actual or reasonably anticipated total revenues from markets administered by the Office of the Interconnection; and

(e) The Capacity Resource is a Generation Capacity Resource for which electricity production is not the primary purpose of the facility at which the energy is produced, but rather it is a byproduct of the resource's primary purpose.

(3) Process for Establishing a Capacity Resource with Actionable Subsidy.

(a) By no later than one hundred twenty (120) days prior to the commencement of the offer period of any Base Residual Auction, each Capacity Market Seller must provide for each Demand Resource, Generation Capacity Resource, and uprate, or planned uprate, of a Generation Capacity Resource that the seller intends to offer into the Base Residual Auction, information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. 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 whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the Base Residual Auction to update the Office of the Interconnection and the Market Monitoring Unit regarding any material changes in the qualifications of the Capacity Resource. The Office of Interconnection and the Market Monitoring Unit may request additional information from the Capacity Market Seller prior to the commencement of the offer period for the Base Residual Auction. Such Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) Business Days upon receipt of the request for additional information.

(b) For each Capacity Resource, an officer of the Capacity Market Seller must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy in accordance with section 5.14(j)(2), and if not, the officer must certify as to which criteria does not apply to the Capacity Resource.

(c) Once a Capacity Resource is a Capacity Resource with Actionable Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status pursuant to section 5.14(j)(5), or by Commission order. All Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status.

(4) Determination of Actionable Subsidy Reference Price.

For purposes of any re-run of the optimization algorithm pursuant to section 5.14(j)(1), the Actionable Subsidy Reference Price for each Capacity Resource with Actionable Subsidy shall be determined in accordance with the procedures below, depending on whether the Capacity Resource with Actionable Subsidy is an Existing Generation Capacity Resource, a Planned Generation Capacity Resource, or a Demand Resource.

(a) Prior to each Base Residual Auction for which a Capacity Market Seller intends to submit a Sell Offer based on an Existing Generation Capacity Resource that is deemed to be a Capacity Resource with Actionable Subsidy, the Office of the Interconnection shall determine an offer price, solely for the purposes of determining an Actionable Subsidy Reference Price under one of the following methods, as applicable:

(i) equal to the higher of:

(A) the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio, the number of Performance Assessment Hours, the Balancing Ratio, and the Capacity Performance bonus payment rate based on the actual market conditions and the actual circumstances of the unit; and

(B) (1) the Avoidable Cost Rate for such resource, without consideration of any Material Subsidy, determined, based on information provided by the Capacity Market Seller in accordance with the procedures and standards of Tariff, Attachment DD, sections 6.4, 6.7, and 6.8, that includes a risk premium for assuming a Capacity Performance obligation and that is net of Projected PJM Market Revenues, or (2) in lieu of using the resource-specific Avoidable Cost Rate calculated in accordance with the procedures and standards of Tariff, Attachment DD, sections 6.4, 6.7, and 6.8, the Capacity Market Seller may elect to use a default Avoidable Cost Rate that is net of Projected PJM Market Revenues. The Office of the Interconnection shall determine and post the default Avoidable Cost Rates for all resource types listed in Tariff, Attachment DD, section 6.7(c)(ii) as well as for nuclear, wind, and solar resources on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. For each Base Residual

Auction, the Office of the Interconnection shall use the values stated in Tariff, Attachment DD, section 6.7(c)(ii) and adjust them based on the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission (“Handy-Whitman Index”) to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The default Avoidable Cost Rates shall be expressed in dollar values for the applicable Delivery Year.

(ii) To the extent the methods expressed in Tariff, Attachment DD, sections 5.14(j)(4)(a)(i) is not applicable, the Actionable Subsidy Reference Price shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resources, as defined in Tariff, Attachment DD, section 6.4(a).

(b) Prior to each Base Residual Auction for which a Capacity Market Seller intends to submit a Sell Offer based on a Planned Generation Capacity Resource that is deemed to be a Capacity Resource with Actionable Subsidy, the Office of the Interconnection shall determine an offer price, solely for the purposes of determining an Actionable Subsidy Reference Price.

(i) The offer price shall be equal to the higher of (A) the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio, the number of Performance Assessment Hours, the Balancing Ratio, and the Capacity Performance bonus payment rate based on the actual market conditions and the actual circumstances of the unit, or (B) the unit-specific offer price for such resource, which includes a risk premium for assuming a Capacity Performance obligation and is net of Projected PJM Market Revenues, that is determined, without consideration of any Material Subsidy, based on information provided by the Capacity Market Seller, and in accordance with the following procedures and standards:

(A) By no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, the Capacity Market Seller shall request a determination of a unit-specific offer price that 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, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals.

(B) The Capacity Market Seller must include in its request: documentation to support the fixed development, construction, operation, and maintenance costs of the Planned Generation Capacity Resource, as well as estimates of offsetting net revenues from PJM-administered markets. The financial modeling assumptions for calculating Cost of New Entry shall be the same modeling assumptions used to determine Cost of New Entry for the RPM auction parameters: (i) nominal levelization of gross costs, (ii) asset life of 20 years, (iii) no residual value, (iv) all project costs included with no sunk costs

excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. 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 proposed Actionable Subsidy Reference Price. 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 an exception hereunder. The request also shall identify all revenue sources relied upon in the proposed Actionable Subsidy Reference Price 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. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably sought by the Office of the Interconnection or the Market Monitoring Unit to evaluate the request. 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.

(C) The Market Monitoring Unit shall review the information and documentation in support of the submission and shall determine whether the requested unit-specific offer price is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than forty-five (45) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all proposed Actionable Subsidy Reference Price submissions and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination of whether the proposed Actionable Subsidy Reference Price is acceptable. If the Office of the Interconnection determines that the proposed Actionable Subsidy Reference Price is not acceptable, it shall calculate and provide to such Capacity Market Seller, a corrected Actionable Subsidy Reference Price based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the

offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the proposed Actionable Subsidy Reference Price is acceptable, the Office of the Interconnection shall notify the Market Monitoring Unit and the Capacity Market Seller, in writing, of the proposed Actionable Subsidy Reference Price by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.

(ii) To the extent the required information is not applicable and the Office of the Interconnection is unable to determine a unit-specific offer price, the Actionable Subsidy Reference Price shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resources, as defined in Tariff, Attachment DD, section 6.4(a).

(c) For Demand Resources the Actionable Subsidy Reference Prices shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resource as defined in Tariff, Attachment DD section 6.4(a).

(5) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy.

In the event the Office of the Interconnection reasonably believes that a certification of a Capacity Resource's status contains or is based on fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource (i) does not qualify as a Capacity Resource with Actionable Subsidy and would not be subject to repricing or (ii) qualifies as a Capacity Resource with Actionable Subsidy and would be subject to repricing, then:

(a) the Office of the Interconnection will provide written notice of suspected fraudulent or material misrepresentation or omission to the Capacity Market Seller no later than sixty (60) days prior to the commencement of the offer period for the Base Residual Auction for which the seller submitted the certification. In such event, a resource that (i) does not qualify as a Capacity Resource with Actionable Subsidy will not be repriced in any re-run of the optimization algorithm conducted in accordance with section 5.14(j)(1) or (ii) qualifies as a Capacity Resource with Actionable Subsidy will be repriced in the re-run of the optimization algorithm conducted in accordance with section 5.14(j)(1). If the Office of the Interconnection, with advice and input from the Market Monitoring Unit, determines that a resource is subject to repricing as a Capacity Resource with Actionable Subsidy, the Office of Interconnection and Market Monitoring Unit may request any relevant documentation to determine the Actionable Subsidy Reference Price in accordance with this section 5.14(j)(5). In such case, the Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) Business Days upon receipt of the request for additional information. The Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary. A Capacity Market Seller may challenge the Office of Interconnection's determination of suspected fraudulent or material misrepresentation or omission by filing a petition with FERC;

(b) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least thirty (30) days before the start of the relevant Base Residual Auction, then the Office of the Interconnection may file the certification that contains any fraudulent or material misrepresentation or omission with FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(c) prior to applying the applicable offer price or Actionable Subsidy Reference Price in any re-run of the optimization algorithm pursuant to section 5.14(j)(1), the Office of the Interconnection, with advice and input of 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 fraudulent or material 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 submit a revised certification for that Capacity Resource for subsequent Base Residual Auctions, including Base Residual 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 fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection 5.14(j)(5) to be requested in any filing to FERC shall not be exclusive of any other actions, remedies, or penalties that may be pursued against the Capacity Market Seller by, including but not limited to, the Office of the Interconnection, the MMU, or others.

5.14A [Reserved.]

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

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

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource’s installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource’s Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction’s impact on the Affected Resource’s existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to

Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

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

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

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

the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

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

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

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

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

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

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

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

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

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each

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

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

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

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

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

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

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

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

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed

0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

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

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

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

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

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

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected

Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

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

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

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

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such

Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

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

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

Attachment B

Revisions to the PJM Open Access Transmission Tariff

Option A

(Clean)

Definitions – A - B**Abnormal Condition:**

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

Acceleration Request:

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

Actionable Subsidy Reference Price:

“Actionable Subsidy Reference Price” shall have the meaning provided in Tariff, Attachment DD, section 5.14(j).

Additional Day-ahead Scheduling Reserves Requirement:

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

Affected System:

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

Affected System Operator:

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

Affiliate:

“Affiliate” shall mean any two or more entities, one of which controls the other or that are under common control. “Control” shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

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

Ancillary Services:

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

Annual Demand Resource:

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

Annual Energy Efficiency Resource:

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

Annual Resource:

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

Annual Resource Price Adder:

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

Annual Revenue Rate:

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

Annual Transmission Costs:

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

Applicable Laws and Regulations:

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

Applicable Regional Entity:

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

Applicable Standards:

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

Applicable Technical Requirements and Standards:

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

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, or to take Transmission

Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

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

Attachment Facilities:

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

Attachment H:

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

Auction Revenue Rights:

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

Auction Revenue Rights Credits:

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

Authorized Government Agency:

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

Avoidable Cost Rate:

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

Balancing Congestion Charges:

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

Balancing Ratio:

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

Base Capacity Demand Resource:

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

Base Capacity Demand Resource Constraint:

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

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a

percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

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

Base Capacity Energy Efficiency Resource:

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

Base Capacity Resource:

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

Base Capacity Resource Constraint:

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

for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

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

Base Capacity Resource Price Decrement:

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

Base Day-ahead Scheduling Reserves Requirement:

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

Base Load Generation Resource

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

Base Offer Segment:

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

Base Residual Auction:

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

Batch Load Demand Resource:

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

Behind The Meter Generation:

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

Black Start Service:

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

Breach:

“Breach” shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

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

Business Day:

“Business Day” shall mean a day in which the Federal Reserve System is open for business and

is not a scheduled PJM holiday.

Buy Bid:

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

Definitions – C-D

Canadian Guaranty:

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

Cancellation Costs:

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

Capacity:

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

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

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

Capacity Import Limit:

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

Capacity Interconnection Rights:

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

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

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

Capacity Performance Transition Incremental Auction:

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

Capacity Resource:

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

Capacity Resource Clearing Price:

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

Capacity Resource with Actionable Subsidy:

“Capacity Resource with Actionable Subsidy” or “Capacity Resources with Actionable Subsidies” shall have the meaning provided in Tariff, Attachment DD, section 5.14(j).

Capacity Storage Resource:

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

Capacity Transfer Right:

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

Capacity Transmission Injection Rights:

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

Cold/Warm/Hot Notification Time:

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

Cold/Warm/Hot Start-up Time:

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

Cold Weather Alert:

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

Collateral:

“Collateral” shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

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

Commencement Date:

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

Commission:

“Commission” shall mean the Federal Energy Regulatory Commission or FERC.

Committed Offer:

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

Completed Application:

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

Compliance Aggregation Area (CAA):

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

Incremental Auction, the same locational price separation in the Third Incremental Auction, *or the same locational price separation in the Final Incremental Auction.*

Conditional Incremental Auction:

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

CONE Area:

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

Confidential Information:

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

Congestion Price:

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

Consolidated Transmission Owners Agreement:

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

Constructing Entity:

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

Construction Party:

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

Construction Service Agreement:

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

Control Area:

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

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

Control Zone:

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

Controllable A.C. Merchant Transmission Facilities:

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

Coordinated External Transaction:

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

Coordinated Transaction Scheduling:

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

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:

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

Costs:

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

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own .

Credit Available for Export Transactions:

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

Credit Available for Virtual Transactions:

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

Credit Breach:

“Credit Breach” shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:

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

Credit Score:

“Credit Score” shall mean a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:

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

CTS Interface Bid:

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

Curtailement:

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

Curtailment Service Provider:

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

Customer Facility:

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

Customer-Funded Upgrade:

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

Customer Interconnection Facilities:

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

Daily Deficiency Rate:

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

Daily Unforced Capacity Obligation:

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

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

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

Day-ahead Energy Market Injection Congestion Credits:

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

Day-ahead Energy Market Transmission Congestion Charges:

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

Day-ahead Energy Market Withdrawal Congestion Charges:

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

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-ahead Scheduling Reserves:

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

Day-ahead Scheduling Reserves Market:

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

Day-ahead Scheduling Reserves Requirement:

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

Day-ahead Scheduling Reserves Resources:

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

Day-ahead Settlement Interval:

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

Day-ahead System Energy Price:

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

Deactivation:

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

Deactivation Avoidable Cost Credit:

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

Deactivation Avoidable Cost Rate:

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

Deactivation Date:

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

Decrement Bid:

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

Default:

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

Delivering Party:

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

Delivery Year:

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

Demand Bid:

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

Demand Bid Limit:

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

Demand Bid Screening:

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

Demand Resource:

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

Demand Resource Factor or DR Factor:

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

Designated Agent:

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

Designated Entity:

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

Direct Assignment Facilities:

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

Direct Load Control:

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

Dispatch Rate:

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

Dynamic Schedule:

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

Dynamic Transfer:

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

Definitions – L – M - N

Limited Demand Resource:

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

Limited Demand Resource Reliability Target:

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

Limited Resource Constraint:

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

Limited Resource Price Decrement:

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

List of Approved Contractors:

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

Load Management:

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

Load Management Event:

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

Load Ratio Share:

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

Load Reduction Event:

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

Load Serving Entity (LSE):

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

Load Shedding:

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

Local Upgrades:

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

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

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

Location:

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

LOC Deviation:

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

unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

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

Locational Deliverability Area Reliability Requirement:

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

Locational Price Adder:

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

Locational Reliability Charge:

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

Locational UCAP:

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

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

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

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

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

Loss Price:

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

Maintenance Adder:

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

Manual Load Dump Action:

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

Manual Load Dump Warning:

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

Market Monitor:

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

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the organization that is responsible for implementing this Plan, including the Market Monitor.

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

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

Market Operations Center:

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

Market Participant:

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

Market Participant Energy Injection:

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

Market Participant Energy Withdrawal:

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

Market Seller Offer Cap:

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

Market Violation:

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

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any

Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Material Subsidy:

“Material Subsidy” shall mean: (1) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource. A Material Subsidy shall not include (3) 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; (4) 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 (5) 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.

Maximum Daily Starts:

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

Maximum Emergency:

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

Maximum Facility Output:

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

Maximum Generation Emergency:

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

Maximum Generation Emergency Alert:

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

Maximum Run Time:

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

Maximum Weekly Starts:

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

Member:

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

Merchant A.C. Transmission Facilities:

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

Merchant D.C. Transmission Facilities:

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

Merchant Network Upgrades:

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

Merchant Transmission Facilities:

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

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Section 36 of the Tariff, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

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

Minimum Annual Resource Requirement:

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

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and

unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

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

Minimum Generation Emergency:

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

Minimum Participation Requirements:

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

Minimum Run Time:

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

MISO:

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

Multi-Driver Project:

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

Native Load Customers:

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

NERC:

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

NERC Interchange Distribution Calculator:

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

Net Benefits Test:

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

Net Cost of New Entry:

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

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts Part II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be

formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

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

Network Customer:

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

Network External Designated Transmission Service:

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

Network Integration Transmission Service:

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

Network Load:

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

Network Operating Agreement:

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

Network Operating Committee:

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

Network Resource:

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

Network Service User:

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

Network Transmission Service:

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

Network Upgrades:

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

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

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

Neutral Party:

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

New PJM Zone(s):

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

New Service Customers:

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

New Service Request:

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

New Services Queue:

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

New Services Queue Closing Date:

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the *six*-month period ending on such date.

New York ISO or NYISO:

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

Nodal Reference Price:

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

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as

determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

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

Nominated Energy Efficiency Value:

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

Non-Firm Point-To-Point Transmission Service:

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

Non-Firm Sale:

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

Non-Firm Transmission Withdrawal Rights:

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

Non-Performance Charge:

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

Nonincumbent Developer:

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

Non-Regulatory Opportunity Cost:

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

Non-Retail Behind The Meter Generation:

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

Non-Synchronized Reserve:

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

Non-Synchronized Reserve Event:

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

Non-Variable Loads:

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

Non-Zone Network Load:

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

Normal Maximum Generation:

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

Normal Minimum Generation:

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

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this Section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting

forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this Section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Section 18.17 of the PJM Operating Agreement.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of Section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this Section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the PJM Market Monitor using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the PJM Market Monitor from a third party which is not, to the Office of the Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this Section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. Disclosure to FERC and CFTC:

1. Notwithstanding anything in this Section I to the contrary, if the FERC, the Commodity Futures Trading Commission (“CFTC”) or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing Section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC’s Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in Section I.B.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this Section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Schedule 10A. Upon receipt of the Authorized Commission’s Certification, the FERC shall provide public notice of the Authorized Commission’s filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission’s Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC’s consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission’s Certification within 90 days of the date of filing, the Certification shall be deemed approved and the

Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this Section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided

however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of Section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding Section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds

for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this Section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this Section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this Section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not

act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in Section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in Section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. Market Monitoring:

1. Subject to the requirements of Section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that the Office of the Interconnection or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of the Office of the Interconnection and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member's confidential information pursuant to Section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure

specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under Section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this Section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.
2. The Market Monitoring Unit shall review the incremental costs (defined in Section 6.4.2 of Schedule 1 of the Operating Agreement) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Schedule 2 of the Operating Agreement.
3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Section 6.4.2 of Schedule 1 of the Operating Agreement is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.
4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Section 6.4 of Schedule 1 of the Operating Agreement. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.
5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. Minimum Generator Operating Parameters:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Section 6.6(c) of Schedule 1 of the Operating Agreement. The Parameter Limited Schedule Matrix shall include

default values on a unit-type basis as specified in Section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Section 6.6 of Schedule 1 of the Operating Agreement and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Section 6.6 of Attachment DD.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to Section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation

Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORD to be included in a Sell Offer applicable to each resource pursuant to Section 6.6(b) of Attachment DD. If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORD to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORD if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Section 5.6.6 of Attachment DD of the PJM Tariff, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in Section II.C.4 above, or (iii) a maximum EFORD that the Market Monitoring Unit believes is inconsistent with the maximum level determined under Section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Section 6.6 of Attachment DD.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Section 6.6 of Attachment DD, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Section 6.6(g) of Attachment DD, to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Section 6.6(i) of Attachment DD, and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. Repricing Sell Offers for Capacity Resources with Actionable Subsidy:

1. Each Capacity Market Seller that submits documentation for the determination an Actionable Subsidy Reference Price pursuant to the requirements set forth in Tariff, Attachment DD, section 5.14(j)(4), the Market Monitoring Unit shall review the documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than forty-five (45) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer the Market Monitoring Unit's determination of whether the requested Actionable Subsidy Reference Price is acceptable.

2. All information submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

D-1. Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy:

1. In the event that the Market Monitoring Unit reasonably believes that a certification of a Capacity Resource's status contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource would be a Capacity Resource with Actionable Subsidy had the certification not contained such misrepresentations or omissions, then it shall notify the Office of the Interconnection and Capacity Market Seller of its findings and provide the Office of the Interconnection with all of the data and documentation supporting its findings, and may take any other action required or permitted under Tariff, Attachment M.

E. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Section 6.7(d) of Attachment DD, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.
2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.
3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Section 6.4(a) of Attachment DD.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. Data Submission:

Pursuant to Section 6.7 of Attachment DD, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Section 6.7(c) of Attachment DD and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Section 6.7 of Attachment DD, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in section 6.7(d) of Attachment DD.

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Section 6.8(d) of Attachment DD, and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Section 6.7(d)(ii) of Attachment DD. The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the

Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Schedule 6A of the PJM Tariff and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Part V of the PJM Tariff from the Office of the Interconnection forwarded pursuant to Section 113.1 of the PJM Tariff, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner

in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Sections 114 and 119 of Part V of the PJM Tariff.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement, discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement.

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Section 5.2.1(b) of Schedule 1 of the Operating Agreement, including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in

the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the repricing provisions of section 5.14(j). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORD, the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, *Final* and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORD values for such Generation Capacity Resources prior to the conduct of the Third *Incremental Auction and Final* Incremental Auction, *as applicable*, for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity of Capacity Resources with Actionable Subsidies; the aggregate megawatt quantity cleared in the RPM Auction of Capacity Resources with Actionable Subsidies; and the aggregate megawatt quantity of Capacity Resources with Actionable Subsidies for any LDA other than those specified in the preceding clause if the LDA has four (4) or more generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth

above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm; provided, however, for each RPM Base Residual Auction conducted for the 2022/2023 Delivery Year and subsequent Delivery Years, once the optimization algorithm clears in any Delivery Year, for the PJM Region, more than 5,000 megawatts of unforced capacity from Capacity Resources with Actionable Subsidy, or for any modeled LDA, a megawatt quantity of Capacity Resources with Actionable Subsidy equal to or exceeding 3.5 percent of that LDA's Reliability Requirement, then the Capacity Resource Clearing Prices for the PJM Region will be determined in accordance with subsection 5.14(j). 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.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

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. If the Sell Offer

price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

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

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.
2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.
3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORD).
4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

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

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

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

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a

separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

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

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. 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 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. 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) [Reserved for Future Use]

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.

j) Repricing to Accommodate Capacity Resources with Actionable Subsidies.

(1) General Rule.

(a) Once the optimization algorithm clears a quantity of Capacity Resources with Actionable Subsidies that is equal to or greater than 5,000 megawatts of unforced capacity for the entire PJM Region in a Base Residual Auction for any Delivery Year, to determine the Capacity Resource Clearing Prices for all Capacity Resources for such Delivery Year and all subsequent Delivery Years, as adjusted as necessary by any applicable Locational Price Adders, the Office of the Interconnection shall re-run the optimization algorithm using the same submitted Sell Offers, but for each Capacity Resource with Actionable Subsidy, the Office of the Interconnection shall apply an Actionable Subsidy Reference Price as determined in accordance with Tariff, Attachment DD, section 5.14(j)(4).

(b) If the initial optimization algorithm clears less than 5,000 megawatts of unforced capacity from Capacity Resources with Actionable Subsidies for the entire PJM Region, but the optimization algorithm clears a quantity of Capacity Resources with Actionable Subsidies that is equal to or greater than 3.5 percent of the Reliability Requirement for any modeled LDA, then, to determine the Capacity Resource Clearing Price for all Capacity Resources for such Delivery Year and all subsequent Delivery Years, as adjusted as necessary by any applicable Locational Price Adders, the Office of the Interconnection shall re-run the optimization algorithm using the same submitted Sell Offers, but for each Capacity Resource with an Actionable Subsidy in that modeled LDA, the Office of the Interconnection shall apply an Actionable Subsidy Reference Price as determined in accordance with Tariff, Attachment DD, section 5.14(j)(4).

(2) Capacity Resources with Actionable Subsidies.

A Capacity Resource that meets all of the following criteria shall be deemed to be a Capacity Resource with Actionable Subsidy:

(a) The Capacity Market Seller formally or informally, directly or indirectly, seeks, recovers, accepts or receives a Material Subsidy with regard to such Capacity Resource;

(b) The Capacity Resource is a Demand Resource or a Generation Capacity Resource or uprate, or planned uprate, to a Generation Capacity Resource that has an Unforced Capacity of 20 MW or greater;

(c) The Capacity Market Seller is a (i) Municipal/Cooperative Entity, which means cooperative and municipal utilities including public power supply entities comprised of either or both of the same, and joint action agencies, or a (ii) Vertically Integrated Utility, which 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) The Material Subsidy the Capacity Market Seller in any way receives for such Capacity Resource is greater than 1% of such Capacity Resource's actual or reasonably anticipated total revenues from markets administered by the Office of the Interconnection; and

(e) The Capacity Resource is a Generation Capacity Resource for which electricity production is not the primary purpose of the facility at which the energy is produced, but rather it is a byproduct of the resource's primary purpose.

(3) Process for Establishing a Capacity Resource with Actionable Subsidy.

(a) By no later than one hundred twenty (120) days prior to the commencement of the offer period of any Base Residual Auction, each Capacity Market Seller must provide for each Demand Resource, Generation Capacity Resource, and uprate, or planned uprate, of a Generation Capacity Resource that the seller intends to offer into the Base Residual Auction, information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. 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 whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the Base Residual Auction to update the Office of the Interconnection and the Market Monitoring Unit regarding any material changes in the qualifications of the Capacity Resource. The Office of Interconnection and the Market Monitoring Unit may request additional information from the Capacity Market Seller prior to the commencement of the offer period for the Base Residual Auction. Such Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) Business Days upon receipt of the request for additional information.

(b) For each Capacity Resource, an officer of the Capacity Market Seller must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy in accordance with section 5.14(j)(2), and if not, the officer must certify as to which criteria does not apply to the Capacity Resource.

(c) Once a Capacity Resource is a Capacity Resource with Actionable Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status pursuant to section 5.14(j)(5), or by Commission order. All Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status.

(4) Determination of Actionable Subsidy Reference Price.

For purposes of any re-run of the optimization algorithm pursuant to section 5.14(j)(1), the Actionable Subsidy Reference Price for each Capacity Resource with Actionable Subsidy shall be determined in accordance with the procedures below, depending on whether the Capacity Resource with Actionable Subsidy is an Existing Generation Capacity Resource, a Planned Generation Capacity Resource, or a Demand Resource.

(a) Prior to each Base Residual Auction for which a Capacity Market Seller intends to submit a Sell Offer based on an Existing Generation Capacity Resource that is deemed to be a Capacity Resource with Actionable Subsidy, the Office of the Interconnection

shall determine an offer price, solely for the purposes of determining an Actionable Subsidy Reference Price under one of the following methods, as applicable:

(i) equal to the higher of:

(A) the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio, the number of Performance Assessment Hours, the Balancing Ratio, and the Capacity Performance bonus payment rate based on the actual market conditions and the actual circumstances of the unit; and

(B) (1) the Avoidable Cost Rate for such resource, without consideration of any Material Subsidy, determined, based on information provided by the Capacity Market Seller in accordance with the procedures and standards of Tariff, Attachment DD, sections 6.4, 6.7, and 6.8, that includes a risk premium for assuming a Capacity Performance obligation and that is net of Projected PJM Market Revenues, or (2) in lieu of using the resource-specific Avoidable Cost Rate calculated in accordance with the procedures and standards of Tariff, Attachment DD, sections 6.4, 6.7, and 6.8, the Capacity Market Seller may elect to use a default Avoidable Cost Rate that is net of Projected PJM Market Revenues. The Office of the Interconnection shall determine and post the default Avoidable Cost Rates for all resource types listed in Tariff, Attachment DD, section 6.7(c)(ii) as well as for nuclear, wind, and solar resources on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. For each Base Residual Auction, the Office of the Interconnection shall use the values stated in Tariff, Attachment DD, section 6.7(c)(ii) and adjust them based on the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission ("Handy-Whitman Index") to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The default Avoidable Cost Rates shall be expressed in dollar values for the applicable Delivery Year.

(ii) To the extent the methods expressed in Tariff, Attachment DD, sections 5.14(j)(4)(a)(i) is not applicable, the Actionable Subsidy Reference Price shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resources, as defined in Tariff, Attachment DD, section 6.4(a).

(b) Prior to each Base Residual Auction for which a Capacity Market Seller intends to submit a Sell Offer based on a Planned Generation Capacity Resource that is deemed to be a Capacity Resource with Actionable Subsidy, the Office of the Interconnection shall determine an offer price, solely for the purposes of determining an Actionable Subsidy Reference Price.

(i) The offer price shall be equal to the higher of (A) the value obtained by incorporating the opportunity cost of Capacity Performance participation in a

manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio, the number of Performance Assessment Hours, the Balancing Ratio, and the Capacity Performance bonus payment rate based on the actual market conditions and the actual circumstances of the unit, or (B) the unit-specific offer price for such resource, which includes a risk premium for assuming a Capacity Performance obligation and is net of Projected PJM Market Revenues, that is determined, without consideration of any Material Subsidy, based on information provided by the Capacity Market Seller, and in accordance with the following procedures and standards:

(A) By no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, the Capacity Market Seller shall request a determination of a unit-specific offer price that 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, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals.

(B) The Capacity Market Seller must include in its request: documentation to support the fixed development, construction, operation, and maintenance costs of the Planned Generation Capacity Resource, as well as estimates of offsetting net revenues from PJM-administered markets. The financial modeling assumptions for calculating Cost of New Entry shall be the same modeling assumptions used to determine Cost of New Entry for the RPM auction parameters: (i) nominal levelization of gross costs, (ii) asset life of 20 years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. 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 proposed Actionable Subsidy Reference Price. 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 an exception hereunder. The request also shall identify all revenue sources relied upon in the proposed Actionable Subsidy Reference Price 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. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably sought by the Office of the Interconnection or the Market Monitoring Unit to evaluate the request. 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.

(C) The Market Monitoring Unit shall review the information and documentation in support of the submission and shall determine whether the requested unit-specific offer price is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than forty-five (45) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all proposed Actionable Subsidy Reference Price submissions and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination of whether the proposed Actionable Subsidy Reference Price is acceptable. If the Office of the Interconnection determines that the proposed Actionable Subsidy Reference Price is not acceptable, it shall calculate and provide to such Capacity Market Seller, a corrected Actionable Subsidy Reference Price based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the proposed Actionable Subsidy Reference Price is acceptable, the Office of the Interconnection shall notify the Market Monitoring Unit and the Capacity Market Seller, in writing, of the proposed Actionable Subsidy Reference Price by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.

(ii) To the extent the required information is not applicable and the Office of the Interconnection is unable to determine a unit-specific offer price, the Actionable Subsidy Reference Price shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resources, as defined in Tariff, Attachment DD, section 6.4(a).

(c) For Demand Resources the Actionable Subsidy Reference Prices shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resource as defined in Tariff, Attachment DD section 6.4(a).

(5) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy.

In the event the Office of the Interconnection reasonably believes that a certification of a Capacity Resource's status contains or is based on fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource (i) does not qualify as a

Capacity Resource with Actionable Subsidy and would not be subject to repricing or (ii) qualifies as a Capacity Resource with Actionable Subsidy and would be subject to repricing, then:

(a) the Office of the Interconnection will provide written notice of suspected fraudulent or material misrepresentation or omission to the Capacity Market Seller no later than sixty (60) days prior to the commencement of the offer period for the Base Residual Auction for which the seller submitted the certification. In such event, a resource that (i) does not qualify as a Capacity Resource with Actionable Subsidy will not be repriced in any re-run of the optimization algorithm conducted in accordance with section 5.14(j)(1) or (ii) qualifies as a Capacity Resource with Actionable Subsidy will be repriced in the re-run of the optimization algorithm conducted in accordance with section 5.14(j)(1). If the Office of the Interconnection, with advice and input from the Market Monitoring Unit, determines that a resource is subject to repricing as a Capacity Resource with Actionable Subsidy, the Office of Interconnection and Market Monitoring Unit may request any relevant documentation to determine the Actionable Subsidy Reference Price in accordance with this section 5.14(j)(5). In such case, the Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) Business Days upon receipt of the request for additional information. The Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary. A Capacity Market Seller may challenge the Office of Interconnection's determination of suspected fraudulent or material misrepresentation or omission by filing a petition with FERC;

(b) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least thirty (30) days before the start of the relevant Base Residual Auction, then the Office of the Interconnection may file the certification that contains any fraudulent or material misrepresentation or omission with FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(c) prior to applying the applicable offer price or Actionable Subsidy Reference Price in any re-run of the optimization algorithm pursuant to section 5.14(j)(1), the Office of the Interconnection, with advice and input of 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 fraudulent or material 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 submit a revised certification for that Capacity Resource for subsequent Base Residual Auctions, including Base Residual 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 fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection 5.14(j)(5) to be requested in any filing to FERC shall not be exclusive of any other actions, remedies, or penalties that may be pursued against the Capacity Market Seller by, including but not limited to, the Office of the Interconnection, the MMU, or others.

5.14A [Reserved.]

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

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

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

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

2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

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

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

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

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

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

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site

that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

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

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

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

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First,

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

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

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

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

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts

or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

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

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

Attachment C

Revisions to the PJM Open Access Transmission Tariff

Option B

(Marked/Redline Format)

Definitions – C-D

Canadian Guaranty:

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

Cancellation Costs:

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

Capacity:

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

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

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

Capacity Import Limit:

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

Capacity Interconnection Rights:

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

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

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

Capacity Performance Transition Incremental Auction:

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

Capacity Resource:

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

Capacity Resource Clearing Price:

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

Capacity Resource with Actionable Subsidy:

“Capacity Resource with Actionable Subsidy” shall have the meaning provided in Tariff, Attachment DD, section 5.14(h)(2).

Capacity Storage Resource:

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

Capacity Transfer Right:

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

Capacity Transmission Injection Rights:

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

Cold/Warm/Hot Notification Time:

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

Cold/Warm/Hot Start-up Time:

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

Cold Weather Alert:

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

Collateral:

“Collateral” shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

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

Commencement Date:

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

Commission:

“Commission” shall mean the Federal Energy Regulatory Commission or FERC.

Committed Offer:

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

Completed Application:

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

Compliance Aggregation Area (CAA):

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

Incremental Auction, the same locational price separation in the Third Incremental Auction, *or the same locational price separation in the Final Incremental Auction.*

Conditional Incremental Auction:

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

CONE Area:

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

Confidential Information:

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

Congestion Price:

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

Consolidated Transmission Owners Agreement:

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

Constructing Entity:

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

Construction Party:

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

Construction Service Agreement:

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

Control Area:

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

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

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

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

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

Control Zone:

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

Controllable A.C. Merchant Transmission Facilities:

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

Coordinated External Transaction:

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

Coordinated Transaction Scheduling:

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

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:

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

Costs:

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

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own .

Credit Available for Export Transactions:

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

Credit Available for Virtual Transactions:

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

Credit Breach:

“Credit Breach” shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:

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

Credit Score:

“Credit Score” shall mean a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:

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

CTS Interface Bid:

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

Curtailement:

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

Curtailment Service Provider:

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

Customer Facility:

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

Customer-Funded Upgrade:

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

Customer Interconnection Facilities:

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

Daily Deficiency Rate:

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

Daily Unforced Capacity Obligation:

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

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

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

Day-ahead Energy Market Injection Congestion Credits:

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

Day-ahead Energy Market Transmission Congestion Charges:

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

Day-ahead Energy Market Withdrawal Congestion Charges:

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

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-ahead Scheduling Reserves:

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

Day-ahead Scheduling Reserves Market:

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

Day-ahead Scheduling Reserves Requirement:

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

Day-ahead Scheduling Reserves Resources:

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

Day-ahead Settlement Interval:

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

Day-ahead System Energy Price:

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

Deactivation:

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

Deactivation Avoidable Cost Credit:

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

Deactivation Avoidable Cost Rate:

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

Deactivation Date:

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

Decrement Bid:

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

Default:

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

Delivering Party:

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

Delivery Year:

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

Demand Bid:

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

Demand Bid Limit:

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

Demand Bid Screening:

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

Demand Resource:

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

Demand Resource Factor or DR Factor:

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

Designated Agent:

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

Designated Entity:

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

Direct Assignment Facilities:

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

Direct Load Control:

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

Dispatch Rate:

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

Dynamic Schedule:

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

Dynamic Transfer:

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

Definitions – L – M - N

Limited Demand Resource:

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

Limited Demand Resource Reliability Target:

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

Limited Resource Constraint:

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

Limited Resource Price Decrement:

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

List of Approved Contractors:

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

Load Management:

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

Load Management Event:

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

Load Ratio Share:

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

Load Reduction Event:

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

Load Serving Entity (LSE):

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

Load Shedding:

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

Local Upgrades:

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

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

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

Location:

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

LOC Deviation:

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

unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

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

Locational Deliverability Area Reliability Requirement:

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

Locational Price Adder:

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

Locational Reliability Charge:

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

Locational UCAP:

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

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

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

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

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

Loss Price:

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

Maintenance Adder:

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

Manual Load Dump Action:

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

Manual Load Dump Warning:

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

Market Monitor:

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

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the organization that is responsible for implementing this Plan, including the Market Monitor.

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

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

Market Operations Center:

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

Market Participant:

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

Market Participant Energy Injection:

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

Market Participant Energy Withdrawal:

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

Market Seller Offer Cap:

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

Market Violation:

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

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any

Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

“Material Subsidy:

“Material Subsidy” shall mean: (1) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource. A Material Subsidy shall not include (3) 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; (4) 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 (5) 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.

Maximum Daily Starts:

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

Maximum Emergency:

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

Maximum Facility Output:

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

Maximum Generation Emergency:

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

Maximum Generation Emergency Alert:

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

Maximum Run Time:

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

Maximum Weekly Starts:

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

Member:

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

Merchant A.C. Transmission Facilities:

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

Merchant D.C. Transmission Facilities:

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

Merchant Network Upgrades:

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

Merchant Transmission Facilities:

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

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Section 36 of the Tariff, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

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

Minimum Annual Resource Requirement:

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

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and

unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

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

Minimum Generation Emergency:

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

Minimum Participation Requirements:

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

Minimum Run Time:

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

MISO:

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

Multi-Driver Project:

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

Native Load Customers:

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

NERC:

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

NERC Interchange Distribution Calculator:

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

Net Benefits Test:

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

Net Cost of New Entry:

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

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts Part II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be

formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

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

Network Customer:

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

Network External Designated Transmission Service:

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

Network Integration Transmission Service:

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

Network Load:

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

Network Operating Agreement:

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

Network Operating Committee:

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

Network Resource:

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

Network Service User:

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

Network Transmission Service:

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

Network Upgrades:

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

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

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

Neutral Party:

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

New PJM Zone(s):

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

New Service Customers:

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

New Service Request:

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

New Services Queue:

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

New Services Queue Closing Date:

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the *six*-month period ending on such date.

New York ISO or NYISO:

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

Nodal Reference Price:

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

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as

determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

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

Nominated Energy Efficiency Value:

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

Non-Firm Point-To-Point Transmission Service:

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

Non-Firm Sale:

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

Non-Firm Transmission Withdrawal Rights:

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

Non-Performance Charge:

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

Nonincumbent Developer:

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

Non-Regulatory Opportunity Cost:

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

Non-Retail Behind The Meter Generation:

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

Non-Synchronized Reserve:

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

Non-Synchronized Reserve Event:

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

Non-Variable Loads:

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

Non-Zone Network Load:

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

Normal Maximum Generation:

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

Normal Minimum Generation:

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

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this Section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting

forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this Section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Section 18.17 of the PJM Operating Agreement.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of Section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this Section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the PJM Market Monitor using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the PJM Market Monitor from a third party which is not, to the Office of the Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this Section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. Disclosure to FERC and CFTC:

1. Notwithstanding anything in this Section I to the contrary, if the FERC, the Commodity Futures Trading Commission (“CFTC”) or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing Section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC’s Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in Section I.B.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this Section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Schedule 10A. Upon receipt of the Authorized Commission’s Certification, the FERC shall provide public notice of the Authorized Commission’s filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission’s Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC’s consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission’s Certification within 90 days of the date of filing, the Certification shall be deemed approved and the

Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this Section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided

however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of Section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding Section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds

for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this Section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this Section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this Section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not

act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in Section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in Section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. Market Monitoring:

1. Subject to the requirements of Section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that the Office of the Interconnection or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of the Office of the Interconnection and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member's confidential information pursuant to Section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure

specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under Section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this Section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.
2. The Market Monitoring Unit shall review the incremental costs (defined in Section 6.4.2 of Schedule 1 of the Operating Agreement) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Schedule 2 of the Operating Agreement.
3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Section 6.4.2 of Schedule 1 of the Operating Agreement is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.
4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Section 6.4 of Schedule 1 of the Operating Agreement. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.
5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. Minimum Generator Operating Parameters:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Section 6.6(c) of Schedule 1 of the Operating Agreement. The Parameter Limited Schedule Matrix shall include

default values on a unit-type basis as specified in Section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Section 6.6 of Schedule 1 of the Operating Agreement and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Section 6.6 of Attachment DD.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to Section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation

Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORD to be included in a Sell Offer applicable to each resource pursuant to Section 6.6(b) of Attachment DD. If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORD to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORD if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Section 5.6.6 of Attachment DD of the PJM Tariff, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in Section II.C.4 above, or (iii) a maximum EFORD that the Market Monitoring Unit believes is inconsistent with the maximum level determined under Section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Section 6.6 of Attachment DD.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Section 6.6 of Attachment DD, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Section 6.6(g) of Attachment DD, to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Section 6.6(i) of Attachment DD, and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. Unit Specific Minimum Sell Offers:

1. If a Capacity Market Seller timely submits an exemption or exception request under Tariff, Attachment DD, Section 5.14(h) of Attachment DD, with all of the required supporting documentation as, the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than forty-five (45) days after receipt of the exemption or exception request its determination whether it believes the requested exemption or exception should be granted in accordance with the standards and criteria set forth in Tariff, Attachment DD, section 5.14(h). If the Market Monitoring Unit determines that the Sell Offer proposed in a Unit-Specific Exception

~~request raises market power concerns, it shall advise the Capacity Market Seller of the minimum Sell Offer in the relevant auction that would not raise market power concerns, with such calculation based on the data and documentation received, by no later than forty-five (45) days after receipt of the request ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.~~

2. All ~~data-information~~ submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

~~3. In the event that the Market Monitoring Unit reasonably believes that a request for a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or a Renewable Portfolio Standard Exemption that has been granted contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller would not have been eligible for the exemption from being a Capacity Resource with Actionable Subsidy for that Capacity Resource had the request not contained such misrepresentations or omissions, then it shall notify the Office of the Interconnection and Capacity Market Seller of its findings and provide the Office of the Interconnection with all of the data and documentation supporting its findings, and may take any other action required or permitted under Attachment M.~~

E. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Section 6.7(d) of Attachment DD, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Section 6.4(a) of Attachment DD.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. Data Submission:

Pursuant to Section 6.7 of Attachment DD, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Section 6.7(c) of Attachment DD and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Section 6.7 of Attachment DD, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in section 6.7(d) of Attachment DD.

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Section 6.8(d) of Attachment DD, and notify the Capacity Market Seller and the Office of the

Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Section 6.7(d)(ii) of Attachment DD. The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Schedule 6A of the PJM Tariff and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Part V of the PJM Tariff from the Office of the Interconnection forwarded pursuant to Section 113.1 of the PJM Tariff, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator

owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Sections 114 and 119 of Part V of the PJM Tariff.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement, discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement.

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Section 5.2.1(b) of Schedule 1 of the Operating Agreement, including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii)

there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORD, the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) In addition to the information required to be posted by subsection (a), PJM will post for a Delivery Year, at least sixty (60) days prior to conducting the Base Residual Auction for such Delivery Year, the aggregate megawatt quantity of, for the PJM Region, all Self-Supply, Competitive, Public Entity, and RPS Exemption requests under Tariff, Attachment DD, section 5.14(h) and such exemptions granted in each such category, and to the extent PJM has made any such determination, notice that PJM has determined that one or more state-sponsored or state-mandated procurement processes is Competitive and Non-Discriminatory pursuant to Tariff, Attachment DD, section 5.14(h).

bc) The information listed in (a) will be posted and applicable for the First, Second, Third, *Final* and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

ed) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

de) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORD values for such Generation Capacity Resources prior to the conduct of the Third *Incremental Auction and Final* Incremental Auction, *as applicable*, for such Delivery Year.

ef) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity requested and granted in the Self-Supply Exemption, Competitive Exemption, Public Entity Exemption, and RPS Exemption categories in the EMAAC, MAAC, and Rest of RTO LDAs/regions; the aggregate megawatt quantity cleared in the RPM Auction for the Self-Supply Exemption, Competitive Exemption, Public Entity Exemption, and Renewable Portfolio Standard Exemption categories; and the aggregate megawatt quantity of the Self-Supply Exemption, Competitive Entry Exemption, Public Power Entity Exemption, and RPS Exemption requested and granted for any LDA other than those specified in the preceding clause if the LDA has more than four generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

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

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

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. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

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

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

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

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

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

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

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

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

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

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

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate

long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. 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 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. 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 based on a Capacity Resource with Actionable Subsidy submitted in any RPM Auction shall have an offer price no lower than the MOPR Floor Offer Price, unless the Capacity Market Seller has obtained a Unit-Specific Exception with respect to such Capacity Resource with Actionable Subsidy in such auction prior to the submission of such offer in accordance with the provisions of this subsection 5.14(h).

(2) Capacity Resource with Actionable Subsidy. A Capacity Resource that meets the following criteria shall be deemed to be a Capacity Resource with Actionable Subsidy:

(a) The Capacity Resource is a Generation Capacity Resource;

(b) The Capacity Market Seller formally or informally, directly or indirectly, seeks, recovers, accepts or receives a Material Subsidy with regard to such Capacity Resource;

(c) The Capacity Resource is not a 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; and

(d) The Capacity Market Seller has not obtained a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or an RPS Exemption for such Capacity Resource, in accordance with the provisions of this subsection 5.14(h).

(3) Process for Establishing a Capacity Resource with Actionable Subsidy.

(a) By no later than one hundred twenty (120) days prior to the commencement of the offer period of any RPM Auction each Capacity Market Seller must provide for each Generation Capacity Resource, and uprate, or planned uprate, of a Generation Capacity Resource that the seller intends to offer into the RPM Auction, information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. 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 whether such Capacity Resource is a Capacity Resource with Actionable Subsidy. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the Office of the Interconnection and the Market Monitoring Unit regarding any material changes in the qualifications of the Capacity Resource. The Office of Interconnection and the Market Monitoring Unit may request additional information from the Capacity Market Seller prior to the commencement of the offer period for the RPM Auction. Such Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) business days upon receipt of the request for additional information.

(b) For each Capacity Resource, an officer of the Capacity Market Seller must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy in accordance with Tariff, Attachment DD, section 5.14(h)(2), and if not, the officer must certify as to which criteria does not apply to the Capacity Resource. The officer must also indicate which, if any, of the exemptions set forth in Tariff, Attachment DD, sections 5.14(h)(7), (8), (9), or (10) apply to the Capacity Resource.

(c) Once a Capacity Resource is a Capacity Resource with Actionable Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status pursuant to Tariff, Attachment DD, section 5.14(h)(12), or by Commission order. All Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status.

(4) MOPR Floor Offer Price. The MOPR Floor Offer Price for a Capacity Resource with Actionable Subsidy shall be the product of the Net Cost of New Entry (applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered) times the average of the Balancing Ratios during the Performance

Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year.

(5) Effect of Exemption or Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a Capacity Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h)(7), (8), (9), or (10), 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 Capacity Resource with Actionable Subsidy 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.

~~(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment.~~

~~The gross Cost of New Entry component of 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"), and a combined cycle generator ("CC") respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) 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) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.~~

| | 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 |

~~(2) Beginning 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.~~

~~——(3)—— 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 CC 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.~~

~~(4)—— Any Sell Offer that is based on:~~

~~i)—— a Generation Capacity Resource located in the PJM Region that is submitted in an RPM Auction for a Delivery Year unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM auction for that or any subsequent Delivery Year; or~~

~~ii)—— a Generation Capacity Resource located outside the PJM Region (where such Sell Offer is based solely on such resource) that requires sufficient transmission investment for delivery to the PJM Region to indicate a long term commitment to providing capacity to the PJM Region, unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell offer based on that resource clears an RPM Auction for that or any subsequent Delivery Year, in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.~~

(5) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer for a Capacity Resource with Actionable Subsidy in any RPM Auction below the

MOPR Floor Offer Price for any Delivery Year may, at its election, submit a request for a Unit-Specific Exception for such Capacity Resource with Actionable Subsidy. Such a request may be in addition to, or in lieu of, a determination that such Capacity Resource is exempt from being a Capacity Resource with Actionable Subsidy via the Self-Supply Exemption, the Competitive Exemption, the Public Entity Exemption, or the RPS Exemption. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-priced 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:

(a) 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 Tariff, Attachment DD, section (h)(11)(a) 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.

(b) For a Unit-Specific Exception for Generation Capacity Resources for which a Sell Offer based on such resource has not cleared in an RPM Auction for any prior Delivery Year, 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 Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry shall be the same modeling assumptions used to determine Cost of New Entry for the RPM Auction parameters: (i) nominal levelization of gross costs, (ii) asset life of twenty (20) years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. 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. In addition to the certification, signed by an officer of the Capacity Market Seller, required by Tariff, Attachment DD, section 5.14(h)(11)(c), the request must include a certification 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.

(c) For a Unit-Specific Exception for Generation Capacity Resources for which a Sell Offer based on such resource has cleared in an RPM Auction for any prior Delivery Year, as more fully set forth in the PJM Manuals, a Capacity Market Seller using a Unit Specific Exception other than the Unit Specific Exception applicable to new entry in accordance with Tariff, Attachment DD, section 5.14(h)(6)(b), shall submit a Sell Offer equal to the higher of the Avoidable Cost Rate, as defined in Tariff, Attachment DD, section 6.8(a), net of Projected PJM Market Revenues, and the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio (A), the number of Performance Assessment Hours (H), the Balancing Ratio (B), and the Capacity Performance bonus payment rate (CPBR) based on the actual market conditions and the actual circumstances of the unit. All supporting data must be provided for all requests.

(d) 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.

(7) Self-Supply Exemption. A Capacity Market Seller that is a Self-Supply LSE may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for a Self-Supply Exemption if such Capacity Resource satisfies the criteria specified below:

(a) Cost and revenue criteria. The costs and revenues associated with a Capacity 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 Capacity Resource in such LSE’s regulated retail rates where such LSE is a Vertically Integrated Utility and the Capacity 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) 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 Capacity 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 Capacity Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the Capacity 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.

(b) 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 Capacity 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 Capacity Resource.

(c) 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 Capacity 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.

| <u>Type of Self-Supply LSE</u> | <u>Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless</u> |
|--------------------------------|--|
| | |

| | |
|--------------------------------------|---|
| | <u>otherwise specified)</u> |
| <u>Single Customer Entity</u> | <u>150 MW</u> |
| <u>Vertically Integrated Utility</u> | <u>20% of LSE's Reliability Requirement</u> |

(d) 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:

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

If the Capacity 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 only the RPM Auction in which such threshold is exceeded.

(e) 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 or existing 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.

(f) For purposes of the Self-Supply Exemption:

(i) “Self-Supply LSE” means the following types of Load Serving Entity, which operate under long-standing business models: Single Customer Entity or Vertically Integrated Utility.

(ii) “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.

(iii) “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.

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

(v) 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.

(vi) 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 Capacity Resource;

provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a Capacity Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(vii) "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 Exemption. To qualify for a Self-Supply Entry exemption, the resource 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 the resource is for the Self-Supply LSE's use to supply its customer(s).

(viii) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the Capacity 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.

(8) Competitive Exemption. A Capacity Market Seller may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for such resource if the Capacity Market Seller demonstrates that such Capacity Resource satisfies all of the following criteria:

(a) No costs of the Capacity Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Tariff, Attachment DD, sections 5.14(h)(8)(b) and (c), to the extent either or both are applicable to such resource, are satisfied.

(b) No costs of the Capacity 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.

(c) The Capacity Market Seller does not receive a Material Subsidy.

(9) Public Entity Exemption. A Capacity Market Seller that is an Electric Cooperative or a Public Power Entity, as defined in Article 1 of the Reliability Assurance Agreement, may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff,

Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for a Public Entity Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that such Capacity Resource satisfies all of the following criteria:

(a) The long-term resource plans for a public entity's Owned and Contracted Capacity, as defined in Tariff, Attachment DD, section 5.14(h)(7), are consistent with its business model and such resource plans are intended to be balanced with its load obligations (i.e., over such long-term planning horizon, the entity's resources are planned to be less than or equal to its LSE Total Estimated Capacity Obligation) (The public entity shall notify the Office of the Interconnection and the Market Monitoring Unit when it expects its Owned and Contracted Capacity to be greater than its LSE Total Estimated Capacity Obligation in the next RPM Delivery Year and describe the consistency of the investment decision with its business model);

(b) The Electric Cooperative's or Public Power Entity's Owned and Contracted Capacity is less than or equal to 600 MW greater than LSE Total Estimated Capacity Obligation in any Delivery Year;

(c) The criteria concerning cost and revenue set forth in Tariff, Attachment DD, section 5.14(h)(7)(a) are satisfied.

Any excess supply, starting with the Capacity Resource(s) most recently added to the portfolio, will be subject to the Minimum Offer Price Rule unless the Capacity Resource qualifies for a Unit-Specific Exception under Tariff, Attachment DD, section 5.14(h)(6), where excess supply is the MW amount of Owned and Contracted Capacity in excess of the sum of LSE Total Estimated Capacity Obligation and 600 MW. The Minimum Offer Price Rule or Unit-Specific Exception shall apply to the last unit(s) added to Owned and Contracted Capacity.

(10) RPS Exemption. A Capacity Market Seller may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for an RPS Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that such Capacity Resource satisfies either:

(a) the following criterion: the Capacity Resource was procured in a program in compliance with a state-mandated renewable portfolio standard prior to December 31, 2018, or based on a request for proposals (RFP) issued under such program prior to December 31, 2018; or

(b) the following criteria:

(i) the Capacity Resource complies with the requirements of a state-mandated renewable portfolio standard or voluntary renewable portfolio standard;

(ii) the terms of such program are competitive and non-discriminatory, meaning that (1) the program requires LSEs to procure a defined amount of renewable Capacity Resources, (2) both new and existing Capacity Resources may participate,

(3) all supplies of renewable Capacity Resources may participate, (4) the requirements of the program are fully objective and transparent, (5) the program terms do not include selection criteria that could give preference to new or existing resources, (6) the program terms do not use indirect means to discriminate against new or existing Capacity Resources, (7) the program terms do not use any locational requirement, e.g., offshore wind, other than restricting imports from other states, and (8) the renewable characteristic is the only screen for participation in the program where renewable does not include coal, natural gas, or nuclear thermal resources;

(iii) if the program does not use an auction, the terms of such program: (1) are consistent with fair market value and standard industry practice and (2) provide that the price paid for renewable energy credits is determined by the contract terms between the buyer and the seller;

(iv) if the program uses an auction either as either a means of procuring renewable attributes to meet state requirements, or as a means to facilitate the procurement of renewable attributes by responsible LSEs, such auction must be competitive and non-discriminatory, meaning (1) winner(s) of auction based on lowest offer prices, (2) payments to winners based on auction clearing price, and (3) at least three non-affiliated sellers participate.

(11) Exemption/Exception Process.

(a) 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.

(b) The Capacity Market Seller must submit its request for a Unit-Specific Exception, or an exemption defined in Tariff, Attachment DD, sections 5.14(h)(7), (8), (9), or (10) 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 Capacity 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 5.14(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.

(c) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has (A) 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 Capacity Resource and seek for such resource either a (1) Unit-Specific Exception from the MOPR Floor

Offer Price or (2) a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or an RPS Exemption from being a Capacity Resource with Actionable Subsidy, and (B), to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception or exemption is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception or exemption; and (3) the request satisfies the criteria for the exception or exemption.

(d) 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.

(12) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy.

In the event the Office of the Interconnection reasonably believes that a certification of a Capacity Resource's status contains or is based on fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource is a Capacity Resource with Actionable Subsidy or does not qualify for a Unit-Specific Exception, then:

(a) the Office of the Interconnection will provide written notice of suspected fraudulent or material misrepresentation or omission 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 the certification. In such event, a resource that is a Capacity Resource with Actionable Subsidy shall be subject to the Minimum Offer Price Rule. The Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection

deems necessary. A Capacity Market Seller may challenge the Office of Interconnection's determination of suspected fraudulent or material misrepresentation or omission by filing a petition with FERC;

(b) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least thirty (30) days before the start of the relevant RPM Auction, then the Office of the Interconnection may file the certification that contains any alleged fraudulent or material misrepresentation or omission with FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(c) prior to applying the Minimum Offer Price Rule, the Office of the Interconnection, with advice and input of 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 fraudulent or material 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 submit a revised certification for that Capacity Resource for subsequent RPM Auctions, including RPM 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 fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection 5.14(h)(12) to be requested in any filing to FERC shall not be exclusive of any other actions, remedies, or penalties that may be pursued against the Capacity Market Seller by, including but not limited to, the Office of the Interconnection, the MMU, or others.

~~A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection 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 process and requirements shall apply to requests for such determinations:~~

~~i) The Capacity Market Seller may request such a determination by no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, 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 the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the minimum offer level expected to be established under subsection (4). If the minimum offer level 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 planned 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 an 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. 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 Minimum Offer Price Rule exception request.

iii) — A Sell Offer evaluated hereunder 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 minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), 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 estimated for subsection (4). 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 an exception hereunder by the Office of the Interconnection.~~

~~iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, 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 to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction~~

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 [Reserved.]

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

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

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by

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

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

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

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent

that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

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

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

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

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

Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

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

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

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

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

if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

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

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

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

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

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

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

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

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

quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

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

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

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

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

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

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

Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

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

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

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

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such

Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

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

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

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

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

Attachment D

Revisions to the PJM Open Access Transmission Tariff

Option B

(Clean)

Definitions – C-D

Canadian Guaranty:

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

Cancellation Costs:

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

Capacity:

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

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

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

Capacity Import Limit:

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

Capacity Interconnection Rights:

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

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

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

Capacity Performance Transition Incremental Auction:

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

Capacity Resource:

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

Capacity Resource Clearing Price:

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

Capacity Resource with Actionable Subsidy:

“Capacity Resource with Actionable Subsidy” shall have the meaning provided in Tariff, Attachment DD, section 5.14(h)(2).

Capacity Storage Resource:

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

Capacity Transfer Right:

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

Capacity Transmission Injection Rights:

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

Cold/Warm/Hot Notification Time:

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

Cold/Warm/Hot Start-up Time:

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

Cold Weather Alert:

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

Collateral:

“Collateral” shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

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

Commencement Date:

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

Commission:

“Commission” shall mean the Federal Energy Regulatory Commission or FERC.

Committed Offer:

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

Completed Application:

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

Compliance Aggregation Area (CAA):

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

Incremental Auction, the same locational price separation in the Third Incremental Auction, *or the same locational price separation in the Final Incremental Auction.*

Conditional Incremental Auction:

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

CONE Area:

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

Confidential Information:

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

Congestion Price:

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

Consolidated Transmission Owners Agreement:

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

Constructing Entity:

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

Construction Party:

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

Construction Service Agreement:

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

Control Area:

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

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

Control Zone:

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

Controllable A.C. Merchant Transmission Facilities:

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

Coordinated External Transaction:

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

Coordinated Transaction Scheduling:

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

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:

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

Costs:

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

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own .

Credit Available for Export Transactions:

“Credit Available for Export Transactions” shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

“Credit Available for Virtual Transactions” shall mean the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

“Credit Breach” shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:

“Credit-Limited Offer” shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Score:

“Credit Score” shall mean a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:

“CTS Enabled Interface” shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling (“CTS”). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., *Schedule A* (PJM Rate Schedule FERC No. 45).

CTS Interface Bid:

“CTS Interface Bid” shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.13*.

Curtailement:

“Curtailement” shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

“Curtailment Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV, *subparts A*.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

“Customer Interconnection Facilities” shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer’s side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

“Daily Deficiency Rate” shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, sections 7, 8, 9, or 13.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

“Day-ahead Congestion Price” shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10*.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions and import transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions and Export Transactions.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-ahead Scheduling Reserves:

“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the Reliability *First* Corporation and SERC.

Day-ahead Scheduling Reserves Market:

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10*.

Day-ahead Scheduling Reserves Requirement:

“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:

“Day-ahead Scheduling Reserves Resources” shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

“Day-ahead System Energy Price” shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

“Deactivation” shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

“Deactivation Avoidable Cost Credit” shall mean the credit paid to Generation Owners pursuant to Tariff, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, section 115 .

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, , or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10.1B*.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10.1B*.

Demand Resource:

“Demand Resource” shall mean a resource with the capability to provide a reduction in demand.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or (“DR Factor”) shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

“Designated Agent” shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

“Designated Entity” shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

“Direct Assignment Facilities” shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Dispatch Rate:

“Dispatch Rate” shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

“Dynamic Transfer” shall have the same meaning provided in the Operating Agreement.

Definitions – L – M - N

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner’s system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Entity (LSE):

“Load Serving Entity” or “LSE” shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the *Real-time Settlement Interval* real-time Locational Marginal Price at the resource’s bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the *Real-time Settlement Interval* integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the

unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the organization that is responsible for implementing this Plan, including the Market Monitor.

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Attachment M of the Tariff, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD, section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any

Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

“Material Subsidy:

“Material Subsidy” shall mean: (1) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource. A Material Subsidy shall not include (3) 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; (4) 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 (5) 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.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified on Attachment T to the Tariff, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Section 36 of the Tariff, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and

unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts Part II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be

formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Article I of the Reliability Assurance Agreement.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Service Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each *six*-month period ending on April 30 and October 31 of each year shall collectively comprise a New Services Queue.

New Services Queue Closing Date:

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the *six*-month period ending on such date.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as

determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

“Nominated Energy Efficiency Value” shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Attachment DD, § 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this Section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting

forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this Section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Section 18.17 of the PJM Operating Agreement.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of Section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this Section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the PJM Market Monitor using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the PJM Market Monitor from a third party which is not, to the Office of the Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this Section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. Disclosure to FERC and CFTC:

1. Notwithstanding anything in this Section I to the contrary, if the FERC, the Commodity Futures Trading Commission (“CFTC”) or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing Section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC’s Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in Section I.B.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this Section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Schedule 10A. Upon receipt of the Authorized Commission’s Certification, the FERC shall provide public notice of the Authorized Commission’s filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission’s Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC’s consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission’s Certification within 90 days of the date of filing, the Certification shall be deemed approved and the

Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this Section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided

however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of Section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding Section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds

for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this Section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this Section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this Section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not

act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in Section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in Section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. Market Monitoring:

1. Subject to the requirements of Section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that the Office of the Interconnection or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of the Office of the Interconnection and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member's confidential information pursuant to Section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure

specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under Section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this Section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.
2. The Market Monitoring Unit shall review the incremental costs (defined in Section 6.4.2 of Schedule 1 of the Operating Agreement) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Schedule 2 of the Operating Agreement.
3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Section 6.4.2 of Schedule 1 of the Operating Agreement is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.
4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Section 6.4 of Schedule 1 of the Operating Agreement. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.
5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. Minimum Generator Operating Parameters:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Section 6.6(c) of Schedule 1 of the Operating Agreement. The Parameter Limited Schedule Matrix shall include

default values on a unit-type basis as specified in Section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Section 6.6 of Schedule 1 of the Operating Agreement and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Section 6.6 of Attachment DD.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to Section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation

Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORD to be included in a Sell Offer applicable to each resource pursuant to Section 6.6(b) of Attachment DD. If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORD to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORD if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Section 5.6.6 of Attachment DD of the PJM Tariff, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in Section II.C.4 above, or (iii) a maximum EFORD that the Market Monitoring Unit believes is inconsistent with the maximum level determined under Section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Section 6.6 of Attachment DD.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Section 6.6 of Attachment DD, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Section 6.6(g) of Attachment DD, to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Section 6.6(i) of Attachment DD, and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. Unit Specific Minimum Sell Offers:

1. If a Capacity Market Seller timely submits an exemption or exception request under Tariff, Attachment DD, section 5.14(h) of Attachment DD, with all of the required supporting documentation as, the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than forty-five (45) days after receipt of the exemption or exception request its determination whether it believes the requested exemption or exception should be granted in accordance with the standards and criteria set forth in Tariff, Attachment DD, section 5.14(h). If the Market Monitoring Unit determines that the Sell Offer proposed in a Unit-Specific Exception

request raises market power concerns, it shall advise the Capacity Market Seller of the minimum Sell Offer in the relevant auction that would not raise market power concerns, with such calculation based on the data and documentation received, by no later than forty-five (45) days after receipt of the request.

2. All information submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

3. In the event that the Market Monitoring Unit reasonably believes that a request for a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or a Renewable Portfolio Standard Exemption that has been granted contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller would not have been eligible for the exemption from being a Capacity Resource with Actionable Subsidy for that Capacity Resource had the request not contained such misrepresentations or omissions, then it shall notify the Office of the Interconnection and Capacity Market Seller of its findings and provide the Office of the Interconnection with all of the data and documentation supporting its findings, and may take any other action required or permitted under Attachment M.

E. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Section 6.7(d) of Attachment DD, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Section 6.4(a) of Attachment DD.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been

determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. Data Submission:

Pursuant to Section 6.7 of Attachment DD, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Section 6.7(c) of Attachment DD and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Section 6.7 of Attachment DD, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in section 6.7(d) of Attachment DD.

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Section 6.8(d) of Attachment DD, and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Section 6.7(d)(ii) of Attachment DD. The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Schedule 6A of the PJM Tariff and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Part V of the PJM Tariff from the Office of the Interconnection forwarded pursuant to Section 113.1 of the PJM Tariff, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Sections 114 and 119 of Part V of the PJM Tariff.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement, discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement.

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Section 5.2.1(b) of Schedule 1 of the Operating Agreement, including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) In addition to the information required to be posted by subsection (a), PJM will post for a Delivery Year, at least sixty (60) days prior to conducting the Base Residual Auction for such Delivery Year, the aggregate megawatt quantity of, for the PJM Region, all Self-Supply, Competitive, Public Entity, and RPS Exemption requests under Tariff, Attachment DD, section 5.14(h) and such exemptions granted in each such category, and to the extent PJM has made any such determination, notice that PJM has determined that one or more state-sponsored or state-mandated procurement processes is Competitive and Non-Discriminatory pursuant to Tariff, Attachment DD, section 5.14(h).

c) The information listed in (a) will be posted and applicable for the First, Second, Third, *Final* and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

d) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

e) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORD values for such Generation Capacity Resources prior to the conduct of the Third *Incremental Auction and Final* Incremental Auction, *as applicable*, for such Delivery Year.

f) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity requested and granted in the Self-Supply Exemption, Competitive Exemption, Public Entity Exemption, and RPS Exemption categories in the EMAAC, MAAC, and Rest of RTO LDAs/regions; the aggregate megawatt quantity cleared in the RPM Auction for the Self-Supply Exemption, Competitive Exemption, Public Entity Exemption, and Renewable Portfolio Standard Exemption categories; and the aggregate megawatt quantity of the Self-Supply Exemption, Competitive Entry Exemption, Public Power Entity Exemption, and RPS Exemption requested and granted for any LDA other than those specified in the preceding clause if the LDA has more than four generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

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. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORD).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or
- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and
- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and
- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate

long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. 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 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. 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 based on a Capacity Resource with Actionable Subsidy submitted in any RPM Auction shall have an offer price no lower than the MOPR Floor Offer Price, unless the Capacity Market Seller has obtained a Unit-Specific Exception with respect to such Capacity Resource with Actionable Subsidy in such auction prior to the submission of such offer in accordance with the provisions of this subsection 5.14(h).

(2) Capacity Resource with Actionable Subsidy. A Capacity Resource that meets the following criteria shall be deemed to be a Capacity Resource with Actionable Subsidy:

(a) The Capacity Resource is a Generation Capacity Resource;

(b) The Capacity Market Seller formally or informally, directly or indirectly, seeks, recovers, accepts or receives a Material Subsidy with regard to such Capacity Resource;

(c) The Capacity Resource is not a 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; and

(d) The Capacity Market Seller has not obtained a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or an RPS Exemption for such Capacity Resource, in accordance with the provisions of this subsection 5.14(h).

(3) Process for Establishing a Capacity Resource with Actionable Subsidy.

(a) By no later than one hundred twenty (120) days prior to the commencement of the offer period of any RPM Auction each Capacity Market Seller must provide for each Generation Capacity Resource, and uprate, or planned uprate, of a Generation Capacity Resource that the seller intends to offer into the RPM Auction, information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. 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 whether such Capacity Resource is a Capacity Resource with Actionable Subsidy. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the Office of the Interconnection and the Market Monitoring Unit regarding any material changes in the qualifications of the Capacity Resource. The Office of Interconnection and the Market Monitoring Unit may request additional information from the Capacity Market Seller prior to the commencement of the offer period for the RPM Auction. Such Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) business days upon receipt of the request for additional information.

(b) For each Capacity Resource, an officer of the Capacity Market Seller must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy in accordance with Tariff, Attachment DD, section 5.14(h)(2), and if not, the officer must certify as to which criteria does not apply to the Capacity Resource. The officer must also indicate which, if any, of the exemptions set forth in Tariff, Attachment DD, sections 5.14(h)(7), (8), (9), or (10) apply to the Capacity Resource.

(c) Once a Capacity Resource is a Capacity Resource with Actionable Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status pursuant to Tariff, Attachment DD, section 5.14(h)(12), or by Commission order. All Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status.

(4) MOPR Floor Offer Price. The MOPR Floor Offer Price for a Capacity Resource with Actionable Subsidy shall be the product of the Net Cost of New Entry (applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered) times the average of the Balancing Ratios during the Performance

Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year.

(5) **Effect of Exemption or Exception.** To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a Capacity Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h)(7), (8), (9), or (10), 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 Capacity Resource with Actionable Subsidy 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.

(6) **Unit-Specific Exception.** A Capacity Market Seller intending to submit a Sell Offer for a Capacity Resource with Actionable Subsidy in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year may, at its election, submit a request for a Unit-Specific Exception for such Capacity Resource with Actionable Subsidy. Such a request may be in addition to, or in lieu of, a determination that such Capacity Resource is exempt from being a Capacity Resource with Actionable Subsidy via the Self-Supply Exemption, the Competitive Exemption, the Public Entity Exemption, or the RPS Exemption. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-priced 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:

(a) 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 Tariff, Attachment DD, section (h)(11)(a) 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.

(b) For a Unit-Specific Exception for Generation Capacity Resources for which a Sell Offer based on such resource has not cleared in an RPM Auction for any prior Delivery Year, 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 Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry shall be the same modeling assumptions used to determine Cost of New Entry for the RPM Auction parameters: (i) nominal levelization of gross costs, (ii) asset life of twenty (20) years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to

build the Capacity Resource. 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. In addition to the certification, signed by an officer of the Capacity Market Seller, required by Tariff, Attachment DD, section 5.14(h)(11)(c), the request must include a certification 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.

(c) For a Unit-Specific Exception for Generation Capacity Resources for which a Sell Offer based on such resource has cleared in an RPM Auction for any prior Delivery Year, as more fully set forth in the PJM Manuals, a Capacity Market Seller using a Unit Specific Exception other than the Unit Specific Exception applicable to new entry in accordance with Tariff, Attachment DD, section 5.14(h)(6)(b), shall submit a Sell Offer equal to the higher of the Avoidable Cost Rate, as defined in Tariff, Attachment DD, section 6.8(a), net of Projected PJM Market Revenues, and the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio (A), the number of Performance Assessment Hours (H), the Balancing Ratio (B), and the Capacity Performance bonus payment rate (CPBR) based on the actual market conditions and the actual circumstances of the unit. All supporting data must be provided for all requests.

(d) 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.

(7) **Self-Supply Exemption.** A Capacity Market Seller that is a Self-Supply LSE may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for a Self-Supply Exemption if such Capacity Resource satisfies the criteria specified below:

(a) **Cost and revenue criteria.** The costs and revenues associated with a Capacity 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 Capacity Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated Utility and the Capacity 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) 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 Capacity 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 Capacity Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the Capacity 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.

(b) **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 Capacity 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 Capacity Resource.

(c) **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 Capacity 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 |
| Vertically Integrated Utility | 20% of LSE's Reliability Requirement |

(d) **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 Capacity 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 only the RPM Auction in which such threshold is exceeded.

(e) 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 or existing 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.

(f) For purposes of the Self-Supply Exemption:

(i) “Self-Supply LSE” means the following types of Load Serving Entity, which operate under long-standing business models: Single Customer Entity or Vertically Integrated Utility.

(ii) “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.

(iii) “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.

(iv) All capacity calculations shall be on an Unforced Capacity basis.

(v) 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.

(vi) 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 Capacity Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a Capacity Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(vii) "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 Exemption. To qualify for a Self-Supply Entry exemption, the resource 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 the resource is for the Self-Supply LSE's use to supply its customer(s).

(viii) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the Capacity 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.

(8) Competitive Exemption. A Capacity Market Seller may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for such resource if the Capacity Market Seller demonstrates that such Capacity Resource satisfies all of the following criteria:

(a) No costs of the Capacity Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Tariff, Attachment DD, sections 5.14(h)(8)(b) and (c), to the extent either or both are applicable to such resource, are satisfied.

(b) No costs of the Capacity 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.

(c) The Capacity Market Seller does not receive a Material Subsidy.

(9) Public Entity Exemption. A Capacity Market Seller that is an Electric Cooperative or a Public Power Entity, as defined in Article 1 of the Reliability Assurance Agreement, may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for a Public Entity Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that such Capacity Resource satisfies all of the following criteria:

(a) The long-term resource plans for a public entity’s Owned and Contracted Capacity, as defined in Tariff, Attachment DD, section 5.14(h)(7), are consistent with its business model and such resource plans are intended to be balanced with its load obligations (i.e., over such long-term planning horizon, the entity’s resources are planned to be less than or equal to its LSE Total Estimated Capacity Obligation) (The public entity shall notify the Office of the Interconnection and the Market Monitoring Unit when it expects its Owned and Contracted Capacity to be greater than its LSE Total Estimated Capacity Obligation in the next RPM Delivery Year and describe the consistency of the investment decision with its business model);

(b) The Electric Cooperative’s or Public Power Entity’s Owned and Contracted Capacity is less than or equal to 600 MW greater than LSE Total Estimated Capacity Obligation in any Delivery Year;

(c) The criteria concerning cost and revenue set forth in Tariff, Attachment DD, section 5.14(h)(7)(a) are satisfied.

Any excess supply, starting with the Capacity Resource(s) most recently added to the portfolio, will be subject to the Minimum Offer Price Rule unless the Capacity Resource qualifies for a Unit-Specific Exception under Tariff, Attachment DD, section 5.14(h)(6), where excess supply is the MW amount of Owned and Contracted Capacity in excess of the sum of LSE Total Estimated Capacity Obligation and 600 MW. The Minimum Offer Price Rule or Unit-Specific Exception shall apply to the last unit(s) added to Owned and Contracted Capacity.

(10) RPS Exemption. A Capacity Market Seller may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in

any RPM Auction for any Delivery Year for an RPS Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that such Capacity Resource satisfies either:

(a) the following criterion: the Capacity Resource was procured in a program in compliance with a state-mandated renewable portfolio standard prior to December 31, 2018, or based on a request for proposals (RFP) issued under such program prior to December 31, 2018; or

(b) the following criteria:

(i) the Capacity Resource complies with the requirements of a state-mandated renewable portfolio standard or voluntary renewable portfolio standard;

(ii) the terms of such program are competitive and non-discriminatory, meaning that (1) the program requires LSEs to procure a defined amount of renewable Capacity Resources, (2) both new and existing Capacity Resources may participate, (3) all supplies of renewable Capacity Resources may participate, (4) the requirements of the program are fully objective and transparent, (5) the program terms do not include selection criteria that could give preference to new or existing resources, (6) the program terms do not use indirect means to discriminate against new or existing Capacity Resources, (7) the program terms do not use any locational requirement, e.g., offshore wind, other than restricting imports from other states, and (8) the renewable characteristic is the only screen for participation in the program where renewable does not include coal, natural gas, or nuclear thermal resources;

(iii) if the program does not use an auction, the terms of such program: (1) are consistent with fair market value and standard industry practice and (2) provide that the price paid for renewable energy credits is determined by the contract terms between the buyer and the seller;

(iv) if the program uses an auction either as either a means of procuring renewable attributes to meet state requirements, or as a means to facilitate the procurement of renewable attributes by responsible LSEs, such auction must be competitive and non-discriminatory, meaning (1) winner(s) of auction based on lowest offer prices, (2) payments to winners based on auction clearing price, and (3) at least three non-affiliated sellers participate.

(11) Exemption/Exception Process.

(a) 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.

(b) The Capacity Market Seller must submit its request for a Unit-Specific Exception, or an exemption defined in Tariff, Attachment DD, sections 5.14(h)(7), (8), (9), or (10) 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 Capacity 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 5.14(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.

(c) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has (A) 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 Capacity Resource and seek for such resource either a (1) Unit-Specific Exception from the MOPR Floor Offer Price or (2) a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or an RPS Exemption from being a Capacity Resource with Actionable Subsidy, and (B), to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception or exemption is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception or exemption; and (3) the request satisfies the criteria for the exception or exemption.

(d) 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.

(12) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy.

In the event the Office of the Interconnection reasonably believes that a certification of a Capacity Resource's status contains or is based on fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource is a Capacity Resource with Actionable Subsidy or does not qualify for a Unit-Specific Exception, then:

(a) the Office of the Interconnection will provide written notice of suspected fraudulent or material misrepresentation or omission 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 the certification. In such event, a resource that is a Capacity Resource with Actionable Subsidy shall be subject to the Minimum Offer Price Rule. The Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary. A Capacity Market Seller may challenge the Office of Interconnection's determination of suspected fraudulent or material misrepresentation or omission by filing a petition with FERC;

(b) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least thirty (30) days before the start of the relevant RPM Auction, then the Office of the Interconnection may file the certification that contains any alleged fraudulent or material misrepresentation or omission with FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(c) prior to applying the Minimum Offer Price Rule, the Office of the Interconnection, with advice and input of 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 fraudulent or material 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 submit a revised certification for that Capacity Resource for subsequent RPM Auctions, including RPM 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 fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection 5.14(h)(12) to be requested in any filing to FERC shall not be exclusive of any other actions, remedies, or penalties that may be pursued against the Capacity Market Seller by, including but not limited to, the Office of the Interconnection, the MMU, or others.

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 [Reserved.]

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an “Affected Resource” and an “Affected Resource Owner,” respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource’s installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource’s Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction’s impact on the Affected Resource’s existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction’s impact on the Affected Resource’s existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource’s capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource’s total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B (“Transition Mechanism”).

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity

Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected

Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in

the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource’s RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for

the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers

requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the

2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

Attachment E

Affidavit of Adam J. Keech
on Behalf of PJM Interconnection, L.L.C.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket No. ER18-____-000

**AFFIDAVIT OF ADAM J. KEECH
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

1. My name is Adam J. Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as the Executive Director, Market Operations for PJM Interconnection, L.L.C. (“PJM”). I am submitting this affidavit on behalf of PJM in support of its proposed market reforms to address the impacts of state resource decisions on PJM’s Reliability Pricing Model.

2. I have served in my current position since 2016 but have served as Director or Senior Director of Market Operations since 2013 where I had very similar responsibilities. The Market Operations Departments at PJM are responsible for technical design, implementation, and clearing of all PJM electricity markets and include the Day-ahead Market Operations Department, the Real-time Market Operations Department, the Market Simulation Department, the Capacity Market Operations Department, and the Interregional Market Operations Department. The responsibilities of these departments includes the Day-ahead and Real-time Energy Markets, Day-ahead Scheduling Reserve Market, Regulation, Synchronized Reserve and Non-Synchronized Reserve Markets, Financial Transmission Rights and Reliability Pricing Model auctions and Market-to-Market coordination between PJM and the Midcontinent Independent System Operator, Inc. and between PJM and the New York Independent System Operator.

3. In my capacity as Executive Director of the Market Operations Departments, I am directly responsible for the development of market rule changes through PJM’s stakeholder process, oversight of the technical implementation of rule changes, and ensuring that PJM’s market operations processes and market clearing results adhere to the requirements detailed in the PJM Open Access Transmission Tariff (“Tariff”) and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.. As Executive Director of the Market Operations Departments, my basic responsibility is to make sure that PJM’s markets are designed in a manner that leads to efficient, intuitive market outcomes that minimize the cost of procurement, meet system reliability needs, and incentivize market participants to act in a manner that promotes system reliability. Prior to assuming my leadership role in Market Operations, I served as Director of Dispatch for PJM where I was responsible for real-time system operations in the control room and compliance with North American Electric Reliability Corporation (“NERC”) standards. Before that, I served as manager of PJM’s Real-time Market Operations Department for three years, where I was directly responsible for PJM’s real-time markets including the Real-Time Energy Market, Regulation, Synchronized Reserve

and Non-Synchronized Reserve Markets in addition to the Real-Time Security Constrained Economic Dispatch tool used by PJM's system operators.

4. I have worked at PJM since January 2003. I hold a Bachelor's of Science degree in Electrical Engineering from Rutgers University in New Brunswick, NJ and a Master's of Science degree in Applied Statistics from West Chester University in West Chester, PA.

5. My affidavit supports PJM's filing of Tariff revisions to fill a gap in the current capacity market rules, which have no mechanism to address the price suppressive effects of below-cost offers from a number of resource types that receive substantial subsidies under various state programs. PJM's Senior Market Strategist, Dr. Anthony Giacomoni in his affidavit provides an overview of the type of state subsidy programs to which PJM's filing responds, and provides estimates of the current and projected megawatts of state-subsidized capacity resource in the PJM Region, and the dollar value of the subsidies. In my affidavit, I discuss when offer behavior is (or is not) competitive, and provide analyses and data showing the likely PJM capacity market impact of the state subsidies. I also support the 5,000 MW transition threshold in the Capacity Repricing proposal by providing an estimate of the megawatt quantity of subsidized resources currently in the PJM Region that would be within the definition of subsidies subject to repricing.

A. Subsidized, Below-Cost Capacity Offers Significantly Reduce Clearing Prices Received by Unsubsidized Competitive Sellers

6. Subsidized, below-cost capacity offers can result in significant and widespread clearing price reductions that are attributable to the subsidies. PJM prepares sensitivity analyses following the Base Residual Auction ("BRA") each year illustrating how additional zero-price offers would have changed the clearing results. Specifically, PJM runs two sensitivities adding first 3,000 MW, and then 6,000 MW, of zero-priced supply to the region outside of MAAC. PJM also runs two sensitivities adding first 3,000 MW, and then 6,000 MW, of zero-priced supply in MAAC. Adding such zero-priced supply is not intended to represent new entry, but rather to illustrate what would happen if supply that originally offered at too high a price to clear the auction instead, relying on a subsidy to help cover its uncompetitive costs, offered at zero price. The injection of this low-priced supply results in a shift to the right of the supply curves by the specified MW amounts. The results from running these four sensitivities for the past three Base Residual Auctions are shown in Attachment 1 focusing on the Locational Deliverability Areas ("LDAs") that show price reductions.

7. As can be seen, adding comparatively small quantities of subsidized offers disproportionately reduces the clearing prices paid to all resources. For example, for the 2020/2021 Delivery Year, the "3000 MW Outside MAAC" scenario adds zero-priced supply of less than 2%, but decreases clearing prices in the RTO unconstrained pricing area by roughly 10%. The "6000 MW Outside MAAC" adds zero-priced supply of less than 4%, but decreases clearing prices in the RTO by 21%. *See* Attachment 1 at 3.

8. For the same Delivery Year, the “3000 MW Inside MAAC” scenario, which assumes about 1,000 MW of the added zero-priced supply is offered in the EMAAC LDA (which represents about 4% of supply in EMAAC), reduces clearing prices in that LDA by nearly 20%. EMAAC clearing prices are reduced *by about one-third* in the second MAAC scenario, which assumes about 2,000 MW of the 6,000 MW of added zero-priced supply (representing about 7% of supply in EMAAC) is offered in EMAAC. *See Attachment 1 at 3.*

9. Notably, these post-BRA sensitivity analyses do not test for how the clearing results would change if *the subsidized offers that actually cleared* in the subject BRA had submitted offers reflecting their competitive net costs. The sensitivities show only what would happen if *additional* subsidized offers were submitted in the BRA. Therefore, the clearing price reductions—relative to what would happen if sellers with subsidies that offered below cost instead offered at a level sufficient to cover the net costs they need from the capacity market—would be even greater than shown here.

B. Subsidized Offers from Specific Resources that Cannot Clear with Cost-Based Offers Would Have Significant Price Suppressive Effects

10. PJM also has simulated capacity auctions that reprice—to zero—only two plants that cannot currently clear at competitive offers that recover their costs. As stated by Exelon in a public announcement, both the Quad Cities plant and Three Mile Island nuclear generating stations failed to clear PJM’s May 2017 BRA.¹ As shown in Attachment 2, allowing just these two plants to offer into the capacity auction at a subsidized price of zero would reduce the capacity revenues received *by every seller in the unconstrained portion of the RTO* by 2%. That 2% revenue reduction, experienced by every cleared seller in the unconstrained part of the RTO, is more significant than it sounds. A seller that clears a resource with 1,000 MW of unforced capacity, for example, would see a \$547,500 reduction in its annual capacity market revenues for a that Delivery Year—due solely to the subsidy.

11. Sellers in the ComEd LDA would see their capacity revenues cut by nearly 10% due solely to allowing the subsidized offer. This would result in a reduction in annual capacity market revenues of \$6.75 million for that same 1,000 MW resource.

12. In the MAAC LDA, the clearing price would drop by \$1/MW-day, as a result of the zero offer from Three Mile Island in that LDA. While this too does not sound very significant, it represents a reduction of \$365,000 in annual capacity market revenues for a resource with 1,000 MW of unforced capacity, and a reduction in total capacity market revenues for the MAAC region of approximately \$24 million.

13. This analysis highlights an important point. Sellers are rational. Sellers that need to cover their costs submit offers at the level necessary to cover their costs.

¹ *Exelon Announces Outcome of 2020-2021 PJM Capacity Auction*, Exelon Corp (May 24, 2017), <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

Cost-recovery offers for Quad Cities and Three Mile Island were submitted in the 2017 BRA—as we know because their offers proved too high to clear. Simply because these resources are operated at a high capacity factor, or are existing resources, does not mean that they have zero costs of committing as capacity or that all of their costs are recovered through energy market revenues. This example is instructive as a reminder of the fundamental economic principles that govern whether or not a rational, unsubsidized seller will submit a zero-price offer.

14. Many sellers submit zero-price offers in PJM’s capacity market. But this does not prove that many sellers are irrational. Sellers estimate whether they will recover their resource’s costs in PJM’s markets. If they anticipate that, for a given Delivery Year, they might not fully recover their resource costs in PJM’s energy and ancillary service markets—and *they are not receiving a subsidy*—then they will offer into the capacity market at a price they consider the minimum needed to continue the operation of their resource through that Delivery Year. Conversely, if a seller anticipates that it will recover its resource costs fully in PJM’s energy and ancillary service markets, then it can safely offer into the capacity market at zero price, because any revenues it receives will be surplus to its revenue requirement. Some sellers may fall in between these two alternatives. If an unsubsidized seller only has limited revenue needs from the PJM capacity market, and it reasonably expects, based on capacity clearing price trends for its LDA, that capacity prices will more than cover its net costs, then the seller might offer at zero price. All three of these scenarios represent rational competitive behavior.

15. By contrast, a zero-priced offer *that is made possible only because a seller receives an out-of-market subsidy* is not competitive behavior. The seller is relying on a state subsidy available only to select resources to submit an offer in the PJM capacity market that is well below what it needs if one looks only at its resource costs and the revenues available to it from PJM’s other markets. The simulation of zero-price offers from Quad Cities and Three Mile Island exemplifies such below-cost subsidized offers. Consequently, the clearing price reductions shown in the simulation are entirely due to uneconomic price suppression.

C. Threshold for Application of Capacity Repricing

16. The Capacity Repricing proposal sets certain threshold levels of subsidized offers that must be passed before subsidized offers will be repriced. For the entire PJM Region, the threshold is 5,000 MW. For individual LDAs, the threshold level is 3.5% of the Reliability Requirement for the LDA. If either threshold is exceeded, all units in that region will be repriced.

17. The threshold, which is necessarily a matter of judgment, provides assurance that subsidies are affecting a significant portion of Capacity Resources before PJM implements this significant rule change. As a further means to assure that repricing will be applied only where subsidies are a significant concern, Capacity Repricing applies only to resources with capacity of at least 20 MW; it only applies if the subsidy is at least 1% of the resource’s expected PJM market revenues; and it does not apply to a process or

installation (such as municipal solid waste or landfill gas) where electrical generation is ancillary to the facility's primary purpose.

18. For reference, PJM has estimated the market penetration of resources with subsidies that would be subject to repricing. PJM reviewed resources across its footprint that could have offered into the 2017 BRA, were eligible to receive a payment from a state-based RPS/REC programs, and would have been repriced based on PJM's proposal. PJM identified 698 MW from resources that could potentially be benefiting from state RPS/REC programs and whose primary commercial function is electricity generation. PJM also identified a total of 981 MW of demand resources and price-responsive demand benefiting from certain specific state programs that subsidize, through general ratepayer revenues, the costs of providing demand curtailment. Last, while it did not clear the 2017 BRA, the Quad Cities plant was subsequently found entitled to a ZEC subsidy in Illinois for its approximately 1,400 MW of PJM Region capacity.

19. In total, based on the last BRA, 3,079 MWs of unforced capacity eligible to receive subsidies would trigger repricing. Since that is short of the 5,000 MW threshold, RTO-wide repricing would not be applied in the May 2019 BRA (i.e., the earliest BRA to which repricing could apply) if the same quantity of unforced capacity persisted. However, 1,674 MW were identified within the ComEd LDA. This exceeds 3.5% of the reliability requirement for that LDA, and thus would trigger repricing.

20. This concludes my affidavit.

Attachment 1
to
Affidavit of Adam J. Keech

2018-2021 BRA Scenario Analysis

| 2018-2019 | | | | | | | | | | | | | | | |
|----------------------------------|--|-----------------|----------|----------|----------|----------|----------|----------|-----------|----------|----------|----------|----------|----------|----------|
| Scenario # | Scenario Description | Auction Results | RTO | MAAC | EMAAC | SWMAAC | PSEG | PS-NORTH | DPL-SOUTH | PEPCO | ATSI | ATSI-C | COMED | BGE | PPL |
| BASE | Actual 2018/19 results | CP RCP | \$164.77 | \$164.77 | \$225.42 | \$164.77 | \$225.42 | \$225.42 | \$225.42 | \$164.77 | \$164.77 | \$164.77 | \$215.00 | \$164.77 | \$164.77 |
| 3 | Add 3000 MW of CP supply to bottom of supply curve in region outside of MAAC (1806 MW in rest of RTO, 760 MW in ComEd, 285 MW in rest of ATSI, 149 MW in ATSI-Cleveland) | CP RCP | \$148.50 | \$149.27 | \$225.36 | \$149.27 | \$225.36 | \$225.36 | \$225.36 | \$149.27 | \$148.50 | \$148.50 | \$174.42 | \$149.27 | \$149.27 |
| Price reduction compared to BASE | | | -\$16.27 | -\$15.50 | -\$0.06 | -\$15.50 | -\$0.06 | -\$0.06 | -\$0.06 | -\$15.50 | -\$16.27 | -\$16.27 | -\$40.58 | -\$15.50 | -\$15.50 |
| 5 | Add 6000 MW of CP supply to bottom of supply curve in region outside of MAAC (3612 MW in rest of RTO, 1520 MW in ComEd, 570 MW in rest of ATSI, 298 MW in ATSI-Cleveland) | CP RCP | \$120.51 | \$149.19 | \$225.38 | \$149.19 | \$225.38 | \$225.38 | \$225.38 | \$149.19 | \$120.51 | \$120.51 | \$160.00 | \$149.19 | \$149.19 |
| Price reduction compared to BASE | | | -\$44.26 | -\$15.58 | -\$0.04 | -\$15.58 | -\$0.04 | -\$0.04 | -\$0.04 | -\$15.58 | -\$44.26 | -\$44.26 | -\$55.00 | -\$15.58 | -\$15.58 |
| 7 | Add 3000 MW of CP supply to bottom of supply curve in MAAC (300 MW in rest of MAAC, 1001 MW in rest of EMAAC, 264 MW in rest of PS, 252 MW in PS-North, 122 MW in DPL-South, 331 MW in PEPCO, 359 MW in BGE, 371 MW in PL) | CP RCP | \$150.00 | \$150.00 | \$185.34 | \$150.00 | \$185.34 | \$185.34 | \$185.34 | \$150.00 | \$150.00 | \$150.00 | \$215.00 | \$150.00 | \$150.00 |
| Price reduction compared to BASE | | | -\$14.77 | -\$14.77 | -\$40.08 | -\$14.77 | -\$40.08 | -\$40.08 | -\$40.08 | -\$14.77 | -\$14.77 | -\$14.77 | \$0.00 | -\$14.77 | -\$14.77 |
| 9 | Add 6000 MW of CP supply to bottom of supply curve in MAAC (600 MW in rest of MAAC, 2002 MW in rest of EMAAC, 528 MW in rest of PS, 504 MW in PS-North, 244 MW in DPL-South, 662 MW in PEPCO, 718 MW in BGE, 742 MW in PL) | CP RCP | \$143.22 | \$143.22 | \$168.74 | \$143.22 | \$168.74 | \$168.74 | \$168.74 | \$143.22 | \$143.22 | \$143.22 | \$215.00 | \$143.22 | \$143.22 |
| Price reduction compared to BASE | | | -\$21.55 | -\$21.55 | -\$56.68 | -\$21.55 | -\$56.68 | -\$56.68 | -\$56.68 | -\$21.55 | -\$21.55 | -\$21.55 | \$0.00 | -\$21.55 | -\$21.55 |

Notes:

- (1) Incremental supply additions and removals have been allocated to LDAs based on LDA pro-rata share of the peak-load of the region to which supply is being added or removed.
- (2) In scenarios 2 through 5, the rest of RTO area includes the AEP, APS, DAY, DEOK, DUQ, DOM and EKPC zones; and the rest of ATSI area includes the ATSI zone outside of the ATSI-Cleveland LDA.
- (3) In scenarios 6 through 9, the rest of MAAC area includes the Penelec and MetEd zones; the rest of EMAAC area includes the AECO, JCPL, PECO zones and the DPL zone outside of the DPL-South LDA; and the rest of PS area includes the PS zone outside of the PS-North LDA.

| 2019-2020 | | | | | | | | | | | | | | | |
|---|--|-----------------|----------|----------|----------|----------|----------|----------|-----------|----------|----------|----------------|----------|----------|----------|
| Scenario # | Scenario Description | Auction Results | RTO | MAAC | EMAAC | SWMAAC | PSEG | PS-NORTH | DPL-SOUTH | PEPCO | ATSI | ATSI-CLEVELAND | COMED | BGE | PPL |
| BASE | Actual 2019/20 results | CP RCP | \$100.00 | \$100.00 | \$119.77 | \$100.00 | \$119.77 | \$119.77 | \$119.77 | \$100.00 | \$100.00 | \$100.00 | \$202.77 | \$100.30 | \$100.00 |
| 3 | Add 3000 MW of CP supply to bottom of supply curve in region outside of MAAC (1966.4 MW in rest of RTO, 655.3 MW in ComEd, 251.7 MW in rest of ATSI, 126.6 MW in ATSI-Cleveland) | CP RCP | \$87.50 | \$100.17 | \$119.77 | \$100.17 | \$119.77 | \$119.77 | \$119.77 | \$100.17 | \$87.50 | \$87.50 | \$197.96 | \$100.30 | \$100.17 |
| Price reduction/increase compared to BASE | | | -\$12.50 | \$0.17 | \$0.00 | \$0.17 | \$0.00 | \$0.00 | \$0.00 | \$0.17 | -\$12.50 | -\$12.50 | -\$4.81 | \$0.00 | \$0.17 |
| 5 | Add 6000 MW of CP supply to bottom of supply curve in region outside of MAAC (3932.7 MW in rest of RTO, 1310.6 MW in ComEd, 503.5 MW in rest of ATSI, 253.2 MW in ATSI-Cleveland) | CP RCP | \$75.00 | \$99.77 | \$119.77 | \$99.77 | \$119.77 | \$119.77 | \$119.77 | \$99.77 | \$75.00 | \$75.00 | \$186.15 | \$100.00 | \$99.77 |
| Price reduction/increase compared to BASE | | | -\$25.00 | -\$0.23 | \$0.00 | -\$0.23 | \$0.00 | \$0.00 | \$0.00 | -\$0.23 | -\$25.00 | -\$25.00 | -\$16.62 | -\$0.30 | -\$0.23 |
| 7 | Add 3000 MW of CP supply to bottom of supply curve in MAAC (300.1 MW in rest of MAAC, 990.4 MW in rest of EMAAC, 259.7 MW in rest of PS, 258.4 MW in PS-North, 119.7 MW in DPL-South, 335.4 MW in PEPCO, 354.8 MW in BGE, 381.5 MW in PL) | CP RCP | \$99.97 | \$99.97 | \$99.97 | \$99.97 | \$99.97 | \$99.97 | \$99.97 | \$99.97 | \$99.97 | \$99.97 | \$202.77 | \$100.70 | \$99.97 |
| Price reduction/increase compared to BASE | | | -\$0.03 | -\$0.03 | -\$19.80 | -\$0.03 | -\$19.80 | -\$19.80 | -\$19.80 | -\$0.03 | -\$0.03 | -\$0.03 | \$0.00 | \$0.40 | -\$0.03 |
| 9 | Add 6000 MW of CP supply to bottom of supply curve in MAAC (600.2 MW in rest of MAAC, 1980.8 MW in rest of EMAAC, 519.4 MW in rest of PS, 516.8 MW in PS-North, 239.4 MW in DPL-South, 670.8 MW in PEPCO, 709.6 MW in BGE, 763.0 MW in PL) | CP RCP | \$95.00 | \$95.00 | \$95.00 | \$95.00 | \$95.00 | \$95.00 | \$95.00 | \$95.00 | \$95.00 | \$95.00 | \$202.77 | \$112.17 | \$95.00 |
| Price reduction/increase compared to BASE | | | -\$5.00 | -\$5.00 | -\$24.77 | -\$5.00 | -\$24.77 | -\$24.77 | -\$24.77 | -\$5.00 | -\$5.00 | -\$5.00 | \$0.00 | \$11.87 | -\$5.00 |

Notes:

- (1) Incremental supply additions and removals have been allocated to LDAs based on LDA pro-rata share of the peak-load of the region to which supply is being added or removed.
- (2) The Rest of RTO area includes the AEP, APS, DAY, DEOK, DUQ, DOM and EKPC zones; and the Rest of ATSI area includes the ATSI zone outside of the ATSI-Cleveland LDA.
- (3) The Rest of MAAC area includes the Penelec and MetEd zones; the Rest of EMAAC area includes the AECC, JCPL, PECO zones and the DPL zone outside of the DPL-South LDA; and the Rest of PS area includes the PS zone outside of the PS-North LDA.

| 2020-2021 | | | | | | | | | | | | | | | | | |
|----------------------------------|--|-----------------|----------|----------|----------|----------|----------|----------|-----------|----------|----------|----------|----------|----------|----------|----------|----------|
| Scenario # | Scenario Description | Auction Results | RTO | MAAC | EMAAC | SWMAAC | PSEG | PS-NORTH | DPL-SOUTH | PEPCO | ATSI | ATSI-C | COMED | BGE | PPL | DAY | DEOK |
| BASE | Actual 2020/21 results | CP RCP | \$76.53 | \$86.04 | \$187.87 | \$86.04 | \$187.87 | \$187.87 | \$187.87 | \$86.04 | \$76.53 | \$76.53 | \$188.12 | \$86.04 | \$86.04 | \$76.53 | \$130.00 |
| 3 | Add 3000 MW of CP supply to bottom of supply curve in region outside of MAAC (1536.1 MW in rest of RTO, 754.8 MW in ComEd, 291 MW in rest of ATSI, 146.3 MW in ATSI-Cleveland, 115.6 MW in DAY, 156.2 MW in DEOK) | CP RCP | \$69.32 | \$86.04 | \$187.87 | \$86.04 | \$187.87 | \$187.87 | \$187.87 | \$86.04 | \$69.32 | \$69.32 | \$185.00 | \$86.04 | \$86.04 | \$69.32 | \$122.50 |
| Price reduction compared to BASE | | | -\$7.21 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | -\$7.21 | -\$7.21 | -\$3.12 | \$0.00 | \$0.00 | -\$7.21 | -\$7.50 |
| 5 | Add 6000 MW of CP supply to bottom of supply curve in region outside of MAAC (3072.2 MW in rest of RTO, 1509.6 MW in ComEd, 582 MW in rest of ATSI, 292.7 MW in ATSI-Cleveland, 231.1 MW in DAY, 312.4 MW in DEOK) | CP RCP | \$60.00 | \$86.04 | \$187.87 | \$86.04 | \$187.87 | \$187.87 | \$187.87 | \$86.04 | \$60.00 | \$60.00 | \$174.36 | \$86.04 | \$86.04 | \$60.00 | \$115.00 |
| Price reduction compared to BASE | | | -\$16.53 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | -\$16.53 | -\$16.53 | -\$13.76 | \$0.00 | \$0.00 | -\$16.53 | -\$15.00 |
| 7 | Add 3000 MW of CP supply to bottom of supply curve in MAAC (302.4 MW in rest of MAAC, 991.6 MW in rest of EMAAC, 259.3 MW in rest of PS, 258 MW in PS-North, 120.1 MW in DPL-South, 336.9 MW in PEPCO, 352.3 MW in BGE, 379.4 MW in PL) | CP RCP | \$74.50 | \$85.00 | \$149.92 | \$85.00 | \$149.92 | \$149.92 | \$149.92 | \$85.00 | \$74.50 | \$74.50 | \$188.12 | \$85.00 | \$85.00 | \$74.50 | \$130.00 |
| Price reduction compared to BASE | | | -\$2.03 | -\$1.04 | -\$37.95 | -\$1.04 | -\$37.95 | -\$37.95 | -\$37.95 | -\$1.04 | -\$2.03 | -\$2.03 | \$0.00 | -\$1.04 | -\$1.04 | -\$2.03 | \$0.00 |
| 9 | Add 6000 MW of CP supply to bottom of supply curve in MAAC (604.9 MW in rest of MAAC, 1983.2 MW in rest of EMAAC, 518.7 MW in rest of PS, 516 MW in PS-North, 240.1 MW in DPL-South, 673.7 MW in PEPCO, 704.6 MW in BGE, 758.8 MW in PL) | CP RCP | \$75.00 | \$75.00 | \$124.70 | \$75.00 | \$124.70 | \$124.70 | \$124.70 | \$75.00 | \$75.00 | \$75.00 | \$188.12 | \$75.00 | \$75.00 | \$75.00 | \$130.00 |
| Price reduction compared to BASE | | | -\$1.53 | -\$11.04 | -\$63.17 | -\$11.04 | -\$63.17 | -\$63.17 | -\$63.17 | -\$11.04 | -\$1.53 | -\$1.53 | \$0.00 | -\$11.04 | -\$11.04 | -\$1.53 | \$0.00 |

Notes:

- (1) Incremental supply additions and removals have been allocated to LDAs based on LDA pro-rata share of the peak-load of the region to which supply is being added or removed.
- (2) The Rest of RTO area includes the AEP, APS, DUQ, DOM and EKPC zones; and the Rest of ATSI area includes the ATSI zone outside of the ATSI-Cleveland LDA.
- (3) The Rest of MAAC area includes the Penelec and MetEd zones; the Rest of EMAAC area includes the AECO, JCPL, PECO zones and the DPL zone outside of the DPL-South LDA; and the Rest of PS area includes the PS zone outside of the PS-North LDA.

Attachment 2
to
Affidavit of Adam J. Keech

2020-2021 BRA Scenario Analysis

| Scenario # | Scenario Description | Auction Results | RTO | MAAC | EMAAC | SWMAAC | PSEG | PS-NORTH | DPL-SOUTH | PEPCO | ATSI | ATSI-C | COMED | BGE | PPL | DAY | DEOK |
|----------------------------------|---|-----------------|---------|---------|----------|---------|----------|----------|-----------|---------|---------|---------|----------|---------|---------|---------|----------|
| BASE | Actual 2020/21 results | CP RCP | \$76.53 | \$86.04 | \$187.87 | \$86.04 | \$187.87 | \$187.87 | \$187.87 | \$86.04 | \$76.53 | \$76.53 | \$188.12 | \$86.04 | \$86.04 | \$76.53 | \$130.00 |
| | Change offers of Quad Cities and Three Mile Island (TMI) nuclear facilities to \$0/MW-day | CP RCP | \$75.00 | \$85.00 | \$187.87 | \$85.00 | \$187.87 | \$187.87 | \$187.87 | \$85.00 | \$75.00 | \$75.00 | \$170.01 | \$85.00 | \$85.00 | \$75.00 | \$130.00 |
| Price reduction compared to BASE | | | -\$1.53 | -\$1.04 | \$0.00 | -\$1.04 | \$0.00 | \$0.00 | \$0.00 | -\$1.04 | -\$1.53 | -\$1.53 | -\$18.11 | -\$1.04 | -\$1.04 | -\$1.53 | \$0.00 |

Notes:

- (1) The Rest of RTO area includes the AEP, APS, DUQ, DOM and EKPC zones; and the Rest of ATSI area includes the ATSI zone outside of the ATSI-Cleveland LDA.
- (2) The Rest of MAAC area includes the Penelec and MetEd zones; the Rest of EMAAC area includes the AECO, JCPL, PECO zones and the DPL zone outside of the DPL-South LDA; and the Rest of PS area includes the PS zone outside of the PS-North LDA.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

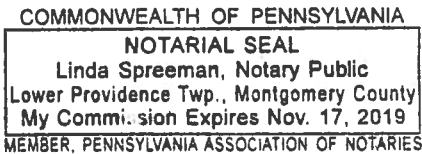
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Docket No. ER18-__-000

Adam J. Keech, being first duly sworn, deposes and states that he is the Adam J. Keech referred to in the foregoing document entitled "Affidavit of Adam J. Keech," 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.



Subscribed and sworn to before me, the undersigned notary public, this 6th day of April, 2018.



Notary Public

My Commission expires: Nov 17, 2019



Attachment F

Affidavit of Dr. Anthony Giacomoni
on Behalf of PJM Interconnection, L.L.C.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket No. ER18-____-000

**AFFIDAVIT OF DR. ANTHONY GIACOMONI
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

1. My name is Anthony Giacomoni. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as a Senior Market Strategist, Emerging Markets, for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its proposed market reforms to address the impacts of state resource decisions on PJM's Reliability Pricing Model.

2. I joined PJM in May 2017. As a Senior Market Strategist, I conduct research and analysis relating to emerging issues in the energy industry and their relevance to wholesale electricity markets. I also support the tracking of issues affecting PJM's strategy as well as the development and expansion of PJM's market and service offerings. Prior to joining PJM, I was a Market Analyst and later Senior Engineer at ISO New England. As a Market Analyst, I worked in the internal market monitoring department where I helped assess the competitiveness of New England's wholesale electricity markets. As a Senior Engineer, I worked in the resource adequacy department where I performed production-cost simulations and electricity market studies related to renewable energy integration, transmission congestion, economic transmission planning, resource planning, and fuel consumption analysis. I hold a Doctor of Philosophy degree in Electrical Engineering and a Master of Science degree in Electrical Engineering from the University of Minnesota. I also hold a Bachelor of Science degree in electric power engineering and economics from Rensselaer Polytechnic Institute.

3. My affidavit supports PJM's filing of Tariff revisions to fill a gap in the current capacity market rules, which have no mechanism to address the price suppressive effects of below-cost offers from a number of resource types that receive substantial subsidies under various state programs. I generally describe the types of state programs at issue, and provide analyses and data showing current and projected potential quantities of subsidized resources, and the per-MW-day dollar value of the subsidies.

A. Overview of State Programs Providing Subsidies to PJM Capacity Resources

4. Certain states in the PJM Region have adopted programs that provide substantial subsidies to resources that sell wholesale services in PJM's markets. These programs directly or indirectly require payments from state loads to resources that meet certain state policy objectives. I provide an overview of the relevant state programs below, grouped by the type of resource addressed by the program.

1. State Zero Emission Credit Subsidies for Nuclear Plants

5. Illinois implemented in 2017 a Zero Emission Credit (“ZEC”) program pursuant to the Future Energy Jobs Act.¹ The ZEC program compensates certain nuclear power plants, including the Quad Cities Generating Station in the PJM Region, for the value of the carbon emissions they avoid. Under FEJA, the state award of ZECs requires a finding that the nuclear plant will not be financially viable (i.e., will not continue to provide zero emission power) if it relies only on PJM wholesale market revenues.² The recipient of the subsidy must commit to continue operating the plant as a condition of receiving the subsidy.³ The subsidy payments adjust in certain circumstances depending on the level of wholesale prices.⁴ The relevant Illinois distribution utilities are responsible for making the ZEC payments to the nuclear plant, and are entitled to collect the cost of those payments from retail customers.⁵ Quad Cities Units 1 and 2 (with a combined capacity of 1,880 MWs) were selected in January 2018 to receive ZEC payments under the Illinois program, at a starting value of \$16.50 per ZEC.⁶

6. New Jersey is moving towards adoption of similar legislation.⁷ On April 5, 2018, the State Assembly Appropriation Committee and the State Senate Budget Committee voted to support a bill that would subsidize nuclear power plants.⁸ The legislation would direct the New Jersey Board of Public Utilities (“NJBPU”) to issue Zero Emission Certificates (“ZECs”) to nuclear power plants selected by the NJBPU to participate in the program. Each ZEC would represent the environmental and fuel diversity attributes of 1 MWh generated by an eligible plant. To participate in the ZEC program, a nuclear plant would have to meet a set of criteria, including demonstrating the facility makes a significant and material contribution to the state’s air quality by minimizing emissions that result from electricity production, and providing financial information to demonstrate that the plant would cease operation within three years

¹ SB 2814, Public Act 099-0906, 99th Gen. Assemb. (Ill. 2016) (“FEJA”).

² 20 Ill. Comp. Stat. 3855/1-75(d-5)(1)(A)(iii) (demonstration of costs necessary to continue operating), (d-5)(1)(C) (selection of winning bids shall take into account preservation of zero emissions facilities that would cease to exist if the ZEC payments were not made to the plant).

³ *Id.*, (d-5)(1)(A)(iv)(commitment to continue operating).

⁴ *Id.*, (d-5)(1)(B)(ZEC payment reduction based on wholesale price index increase).

⁵ *Id.*, (d-5)(6) (electric utilities entitled to recover all costs associated with ZEC procurement through automatic adjustment clause tariff).

⁶ Public Notice of Successful Bidders and Average Prices, Illinois Commerce Commission (Jan. 25, 2018), https://www.ipa-energyrfp.com/?wpfb_dl=1450.

⁷ See S. 2313, 218th Leg., Reg. Sess. (N.J. 2018) (“NJ ZEC Bill”).

⁸ Tom Johnson, *Amid Arguments and Warnings, Nuclear Subsidy Bill Clears Committee*, NJ Spotlight (Apr. 6, 2018), <http://www.njspotlight.com/stories/18/04/06/amid-arguments-and-warnings-nuclear-subsidy-bill-clears-committee/>.

without a material financial change.⁹ The NJBPU is to select eligible nuclear power plants meeting the criteria, but not beyond the point where the selected units generate 40% of the energy delivered in the state,¹⁰ which the legislature recognized is the approximate level of nuclear generation on which New Jersey's residents and business rely for their electricity needs.¹¹ ZEC costs would be recovered through a non-bypassable irrevocable charge of \$0.004/kwh assessed on retail distribution customers.¹²

2. State Subsidy Programs for Offshore Wind Generation

7. The Maryland Offshore Wind Energy Act of 2013¹³ changed the state's renewable portfolio standard to include a specified quantity of offshore wind; established an application process for proposed offshore wind energy projects; and set limits on the retail rate impact from paying for the environmental attributes of offshore wind projects.¹⁴ OWEA provides for offshore wind renewable energy credits ("ORECs") that, unlike typical renewable energy credits ("RECs") will be bundled with the energy, capacity, and ancillary services supplied by the offshore generator. OWEA caps the price of these ORECs at \$190/MWh (in 2012 dollars).¹⁵ The legislature, in an accompanying Fiscal and Policy Note, showed that the environmental attributes would comprise about \$123/MWh of the value of a \$190/MWh OREC, based on then-estimated PJM market prices for energy, capacity, and ancillary services.¹⁶

8. The Maryland Public Service Commission ("MdPSC") is to set an OREC price schedule when it approves an offshore wind project, and will set the annual percentage OREC obligation each year for competitive suppliers—in sufficient time for suppliers to take that requirement into account when developing the rates they offer customers.¹⁷ An offshore project that receives OREC revenue must sell its energy, capacity, and ancillary services into PJM's markets, and must distribute its revenues from

⁹ NJ ZEC Bill at § 3(e).

¹⁰ *Id.* at § 3(g).

¹¹ *Id.* at § 1(b)(5).

¹² *Id.* at § 3(j)(1). For reference, annual energy deliveries to end-users in New Jersey are on the order of 70,000 gigawatt-hours.

¹³ Md. Code Ann., Pub. Util. § 7-704.2 ("OWEA").

¹⁴ OWEA § (a)(1)-(4).

¹⁵ Md. General Assembly, Dep't of Legislative Servs., Fiscal and Policy Note (Revised), Maryland Offshore Wind Energy Act of 2013, H.D. 226, Reg. Sess., at 6 (2013).

¹⁶ *Id.* at 4, Exhibit 1.

¹⁷ OWEA § (d)(1)-(3).

such sales to the Maryland electric companies, to be credited to retail customers in proportion to their consumption of electricity supply.¹⁸

9. The MdPSC in 2016 opened a proceeding to evaluate and compare¹⁹ the two proposed offshore wind projects that met OWEA's minimum threshold requirements: (i) U.S. Wind, Inc. proposing a 250 MW project that it states would meet 100% of the state's offshore wind Renewable Portfolio Standard ("RPS") requirement;²⁰ and (ii) Skipjack Offshore Wind, LLC, proposing a 120 MW project.²¹ U.S. Wind and Skipjack anticipate in-service dates of 2020 and 2021, respectively (although presumably only one of the two will go forward).

10. New Jersey recently took steps to promote development of offshore wind generation under a 2010 law. Specifically, on January 31, 2018, New Jersey Governor Philip D. Murphy issued Executive Order No. 8 which, among other things, directed the NJBPU to (i) establish the OREC program contemplated by the New Jersey Offshore Wind Economic Development Act of 2010;²² (ii) approve OREC pricing plans as outlined in that act; (iii) establish an OREC funding mechanism, addressing the flow of payments for ORECs from suppliers to offshore wind developers; and (iv) issue a solicitation calling for proposed offshore wind projects for the generation of 1,100 MW of electric power, "the nation's largest such solicitation to date."²³

11. On February 28, 2018, the NJBPU responded to Executive Order No. 8 by opening a proceeding to, among other things, develop and establish the required OREC funding mechanism; and "[p]repare for the solicitation of the initial 1,100 MW goal of offshore wind capacity."²⁴

¹⁸ OWEA § (c)(3)(i)-(ii).

¹⁹ *See In the Matter of the Applications of US Wind, Inc. and Skipjack Offshore Wind, LLC for a Proposed Offshore Wind Project(s) Pursuant to the Maryland Offshore Wind Energy Act of 2013*, MdPSC Case No. 9431, Order No. 87898 (Nov. 22, 2016).

²⁰ U.S. Wind's project is describe on its website at <http://www.uswindinc.com/maryland-offshore-wind-project/>.

²¹ Skipjack's project is described on its website at <http://dwwind.com/project/skipjack-wind-farm/>.

²² *See* 2010 N.J. Ch. 57, 2010 N.J.S.N. 2036.

²³ Philip D. Murphy, Governor, New Jersey, *Executive Order No. 8*, ¶ 5 (Jan. 31, 2018), <http://nj.gov/infobank/eo/056murphy/pdf/EO-8.pdf>.

²⁴ *In the Matter of the Implementation of Executive Order No. 8 on Offshore Wind and the Initiation of an OREC Funding Mechanism and Rulemaking Process*, NJBPU Docket No. QO18020151, ¶ 4 (Feb. 28, 2018).

3. State REC Subsidies Under Mandatory Renewable Portfolio Standard Programs

12. Many states (and the District of Columbia) in the PJM Region have mandatory RPS programs that grant tradable rights to resource owners to value the environmental attributes of their renewable resources. These programs are a significant, and growing, source of out-of-market revenue for eligible PJM resources.

13. While the specifics differ from state to state, generally each program requires that renewable resources (as defined by the state program) must supply a certain percentage of the annual electric energy consumption in the state. The programs specify a required minimum percentage for a specified end date, and typically also set steadily increasing minimum percentages for the years leading to that end date.

14. To enforce these requirements, load serving entities (“LSEs”) serving load in the state must show for each year that specific renewable resources provided sufficient energy to meet the minimum percentage requirement for the LSE’s loads. To the extent the LSE cannot make that showing, it must pay a penalty, often referenced in the industry as an Alternative Compliance Payment (“ACP”), at a \$/MWh rate prescribed by the state program, for each MWh of the minimum energy requirement the LSE failed to meet with renewable resources.

15. To meet the requirement, the LSE may build or contract for a qualifying renewable resource, or it may purchase a REC from a qualified renewable resource. RECs are a function of the state program, and are issued for each MWh of energy a qualified renewable resource generates. RECs are tradable, permitting the renewable resource to sell its RECs, directly or indirectly, to LSEs that use them to demonstrate satisfaction of their RPS obligations.²⁵ The value of RECs is based on the ACP, the demand set by the applicable RPS obligation, and the installation of qualifying renewable resources. The ACP penalty rate, which is an alternative to purchasing a REC, and thus effectively caps the price a renewable resource operator can get for selling its REC, is a state policy choice. So too is the demand for RECs, as dictated by the state-mandated RPS percentage requirement for the applicable year. RECs are bought and sold within the value parameters set by these state policy choices.²⁶ RECs thus provide a state-established revenue stream, separate from the revenue available from sale of the energy, capacity, or ancillary services, to support the creation and continued operation of the renewable resource.

²⁵ RECs that embody only environmental attributes, unbundled from energy, are not subject to the Commission’s Federal Power Act jurisdiction. *WSPP Inc.*, 139 FERC ¶ 61, 061, at PP 17-26 (2012).

²⁶ Most REC sales are effected through intermediaries such as brokers or aggregators/resellers. PJM’s Generation Attribute Tracking System provides a registry of the creation and disposition of RECs from qualifying renewable facilities that supports state RPS and REC programs in the PJM Region.

16. The PJM Region states of New Jersey, Maryland, Pennsylvania, Delaware, Ohio, and Illinois, and the District of Columbia, have mandatory RPS programs that generally track the broad outline above. DSIRE, an on-line reference funded by the U. S. Department of Energy and operated by the North Carolina Clean Energy Technology Center at North Carolina State University, which describes itself as “the most comprehensive source of information on incentives and policies that support renewable energy and energy efficiency in the United States” provides a more detailed summary of these state programs.²⁷

17. PJM notes that the subsidy of concern under RPS programs, i.e., RECs, have seen significant price declines in many PJM states recently, reflecting that the supply of eligible renewable energy generation has caught up with current RPS requirements in those states.²⁸ As noted above, however, REC prices are driven by state policy choices, i.e., the minimum RPS percentage requirements, and the ACP penalty levels, which states may change over time through further legislation. The latest state legislative trend, recently exemplified in the PJM Region by Illinois, Maryland, and the District of Columbia, is to strengthen RPS requirements,²⁹ which will tend to support REC prices going forward.

B. Subsidies Under These State Programs Appear to Contribute Meaningfully to the Development or Retention of the Resources that Are the Subject of the Program

18. The PJM Region state programs described above are expressly designed to promote the development or retention of specific types of resources. Available evidence indicates that they do indeed contribute to that objective. While my affidavit does not attempt to calculate whether each resource that receives a state subsidy would not enter service, or would not remain in service, without the subsidy, it is reasonable to conclude, as a general matter, that these subsidies cause more MWs of the favored resource types to be in service than would be the case without the state subsidies. In other words, without these subsidies from outside the PJM wholesale market, some portion of these subsidized resources would not be economic.

²⁷ New Jersey (<http://programs.dsireusa.org/system/program/detail/564>); Maryland (<http://programs.dsireusa.org/system/program/detail/1085>); Pennsylvania (<http://programs.dsireusa.org/system/program/detail/262>); Delaware (<http://programs.dsireusa.org/system/program/detail/1231>); Ohio (<http://programs.dsireusa.org/system/program/detail/2934>); Illinois (<http://programs.dsireusa.org/system/program/detail/584>); District of Columbia (<http://programs.dsireusa.org/system/program/detail/303>).

²⁸ Galen Barbose, *U.S. Renewables Portfolio Standards 2017 Annual Status Report*, Lawrence Berkeley National Laboratory, 30 (July 2017), <http://eta-publications.lbl.gov/sites/default/files/2017-annual-rps-summary-report.pdf> (“LBL 2017 RPS Status Report”).

²⁹ *Id.* at 10.

19. In some cases, this linkage has been made explicit by the plant owners. For example, in May 2017, before being formally selected to receive the ZEC subsidy, Quad Cities failed to clear PJM's Base Residual Auction for the 2020/2021 Delivery Year.³⁰ In its announcement of that auction result, plant owner Exelon Corp. ("Exelon") explained that it "remains fully committed to keeping the Quad Cities plant open, provided that FEJA's Zero Emissions Credit program is implemented as expected and provided that Quad Cities is selected to participate."³¹

20. Similarly, on March 2, 2018, PSEG Power, LLC ("PSEG"), the co-owner,³² with Exelon, of the Salem Nuclear Generating Station in New Jersey, filed a Form 8-K with the United States Security and Exchange Commission, advising that the co-owners had agreed to "cancel the funding of [certain] future capital projects" at the Salem plant. PSEG further conveyed the co-owners' agreement "that the funding of these projects may be restored when and if legislation is enacted in New Jersey that sufficiently values the attributes of nuclear generation and Salem benefits from such legislation."³³ PSEG also advised that "similar actions may be appropriate at its wholly-owned Hope Creek generating station in New Jersey as well, and the assessment of this is continuing."³⁴ In addition, as noted above, the NJ ZEC Bill conditions selection of a plant to receive ZEC payments on a showing that it would cease operation within three years without a material financial change.

21. As to RPS programs, states specifically intended that these policies would promote investment in renewable resources.³⁵ Research affirms that RPS/REC programs contribute significantly to the installation of renewable resource capacity. For example, the Lawrence Berkeley National Laboratory found last year that mandatory RPS policies

³⁰ *Exelon Announces Outcome of 2020-2021 PJM Capacity Auction*, Exelon Corp. (May 24, 2017), <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017> (stating that failure to clear "highlight[s] the challenge nuclear energy continues to face without compensation for its ability to produce electricity without harmful carbon and air pollution").

³¹ *Id.*

³² PSEG owns its share of the plant through a subsidiary, PSEG Nuclear, LLC.

³³ Public Service Enterprise Group Incorporated and PSEG Power LLC, *Form 8-K*, U.S. Securities and Exchange Commission (Mar. 2, 2018), <http://app.quotemedia.com/data/downloadFiling?ref=12101380&type=HTML&symbol=PEG&companyName=Public+Service+Enterprise+Group+Incorporated&formType=8-K&formDescription=Report+of+unscheduled+material+events+or+corporate+changes.&dateFiled=2018-03-02>.

³⁴ *Id.*

³⁵ The Illinois FEJA, for example, includes the finding of the General Assembly that "the State should encourage . . . investment in renewable energy resources." FEJA § 1(a)(1).

have been a “key driver” for renewable energy generation growth;³⁶ and that the RPS role has been “seemingly most critical” in, among other regions, the Mid-Atlantic (defined for their study as states primarily in the PJM Region) where “actual [renewable energy] growth closely matches RPS needs.”³⁷ The same study contrasts development of renewable resources in states with and without RPS requirements, and shows that development of the state-desired resources is greater in states with RPS requirements.³⁸

22. Whether REC revenues make an individual project economic will depend on many factors. A 2011 study by the National Renewable Energy Laboratory, for example, found that “[w]hile there is no single answer to the role that RECs play in developing new renewable energy projects, there are situations in which REC revenues are essential to project economics, as well as some where REC revenues may have little impact.”³⁹

23. Despite that uncertainty for individual projects, it is clear, as a general matter, that mandatory RPS/REC programs are contributing to renewable resource investment, given that state policymakers’ interim goals for renewable resource penetration are being met. An independent analysis in mid-2017 showed that Pennsylvania, Ohio, New Jersey, Maryland, Delaware, and the District of Columbia had each met 100% of their RPS requirements (for the most-recent compliance year available for each state) with either renewable energy or RECs.⁴⁰ The analysis showed that Illinois had met 60% of its requirement, and explained that the shortfall was related to the fact that Illinois requires alternative retail suppliers to meet 50% of their RPS obligations by paying ACPs, rather than purchasing RECs.⁴¹ In simple terms, the RPS programs in the PJM Region are doing what they were intended to do, i.e., increase the share of state loads’ energy needs that is met by renewable resources, and generally bring forth more renewable resources in the PJM Region than would have developed absent the programs.

C. The State Programs Provide Subsidies to Thousands of MWs of Capacity, and that Number Will Grow Significantly in Coming Years

24. The state programs described above provide subsidies to thousands of MWs of PJM Capacity Resources, and that number is scheduled to grow significantly under current law.

³⁶ *LBL 2017 RPS Status Report* at 12.

³⁷ *Id.* at 13.

³⁸ *See id.* at 14-16.

³⁹ Edward Holt, Jenny Sumner, Lori Bird, *The Role of Renewable Energy Certificates in Developing New Renewable Energy Projects*, National Renewable Energy Laboratory, v (June 2011), <https://www.nrel.gov/docs/fy11osti/51904.pdf>.

⁴⁰ *LBL 2017 RPS Status Report* at 28.

⁴¹ *Id.*

25. As noted above, the Illinois ZEC program provides payments to Exelon for both Unit 1 and Unit 2 of Quad Cities, which Mr. Keech notes have a PJM Region capacity of approximately 1,400 MWs. If the New Jersey legislation endorsed by the state appropriation and budget committees in April 2018 is adopted and both the Salem and Hope Creek plants are found eligible, then that program would subsidize approximately 3360 MWs of PJM Region capacity.

26. As also explained above, the Maryland program authorized by the Maryland Offshore Wind Energy Act of 2013 contemplates up to 250 MW of offshore wind, while the New Jersey program authorized by the New Jersey Offshore Wind Economic Development Act of 2010 contemplates up to 1,100 MW of offshore wind as an initial phase.

27. State RPS programs also provide subsidies to thousands of MWs of capacity. As shown above, RPS states are mostly meeting their RPS percentage requirements. If they continue to meet those requirements, the RPS percentages prescribed by state law provide a good basis for estimating the MWs of capacity that will receive subsidies under these programs. To estimate these MWs, PJM prepared the analysis reflected in Attachment 1 to this affidavit. That analysis shows:

- The RPS percentage requirements by state for each year from 2009 through 2033;
- The historic and projected annual energy consumption by state for each of those years based on PJM's 2018 Annual Load Forecast Report;
- The RPS energy requirement by state and year, after applying the RPS percentage to the corresponding load;
- The aggregate RPS energy requirement for all states, by year, in the PJM Region, adjusted to reflect states with only part of their loads in the PJM Region;
- The percentage of PJM Region load, by year, that must be met by RPS required resources; and
- The estimated capacity needed in the PJM Region, by year, to supply the RPS energy requirement for the PJM Region.

28. PJM's estimates reflect the historic experience that approximately one-third of the state RPS requirements are met with behind-the-meter resources in the PJM Region, or with resources located outside the PJM Region, or with ACP payments (e.g., in Illinois).

29. As can be seen on the last line of Attachment 1, PJM estimates that 4,969 MWs of "around-the-clock" capacity (located and metered in the PJM Region) are needed in 2018 to generate the RPS requirements for energy in the PJM Region. The "around-the-clock" assumption ignores differing capacity factors of RPS resources and

assumes all capacity needed to meet RPS needs will operate at 100 % capacity factor—meaning the assumption is very conservative, and actual capacity to meet RPS requirements would be higher. PJM estimates that the RPS “around-the-clock” capacity requirement will exceed 8,000 MWs by 2025; and will increase to 8,866 MWs by the end of the analysis period in 2033.

30. To be clear, not all of these resources may depend on the state subsidies to be economic. Some existing resources, for example, may have avoidable costs that are low enough to be met with other PJM market revenues. However, as described above, some resources are relying on state subsidies to be economic.

D. ZECs, RECs and SRECs Are a Large Source of Out-of-Market Revenue, Comparable to or Exceeding PJM Capacity Market Revenues

31. The out-of-market financial support provided by the state programs at issue is substantial. To help put this in perspective, PJM has compared the subsidies to prices paid to resources that clear PJM’s capacity market. PJM and the Commission have, since the Reliability Pricing Model was implemented, relied on capacity market clearing prices to provide a meaningful signal whether a new resource should enter PJM’s market, or an existing resource should exit the market. This signaling function assumes that capacity market revenues supply a significant share of the revenues—beyond those available in the PJM energy and ancillary services markets—a competitive resource needs to cover its costs. A revenue source comparable to the PJM capacity market therefore is a significant revenue source, which could meaningfully affect whether or not a resource is economic. As I show below, the state subsidies provided by the programs described above are indeed comparable to (or exceed) PJM capacity market revenues.

32. I have restated the subsidies, typically paid per MWh generated, to a MW-day price like those used in the capacity market. The key variables are the \$/MWh subsidy price and the resource’s capacity factor. If the estimated capacity factor is reasonably accurate, the subsidized resource would receive approximately the same revenue at a \$/MW-day rate as it would receive at a \$/MWh rate. My analysis, discussed below and set forth in Attachment 2, uses reasonable resource-class capacity factors for the resource types at issue. The analysis also takes account of any state program features, such as overall revenue caps, that affect the subsidy payments.

33. The \$/MWh values are the estimated payment rates for ZECs, RECs, and Solar RECs (“SRECs”) under the programs described above, as set by statute, rule, or in exchange markets. The analysis underscores that these sustained, consistent payments, awarded for every MWh without regard to energy market conditions, can add up quickly over the year, such that even a seemingly modest per-MWh rate can easily outpace the payments resources receive from clearing the PJM capacity market.

34. Attachment 2 then shows the \$/MW-day state subsidy payments, which can be compared to the \$/MW-day clearing prices PJM reported for its most recent Base Residual Auction for the Locational Deliverability Area (“LDA”) corresponding to the particular state at issue. As can be seen, the Illinois ZEC program equates to a subsidy of

\$265/MW-day. By comparison, the most recent Base Residual Auction clearing price for the ComEd LDA in PJM's capacity market was \$188/MW-day. Similarly, REC payments to onshore wind in New Jersey equate to a subsidy of \$250/MW-day, while those to onshore wind in Delaware equate to a subsidy of \$253/MW-day, both well above the clearing price of \$188/MW-day in the EMAAC LDA.

35. Solar REC ("SREC") payments tend to be much higher still. In New Jersey, SREC payments equate to a subsidy of \$2,575/MW-day, while SREC payments in D.C. equate to a subsidy of \$4,751/MW-day.

36. I should point out that while these subsidies are quite substantial, the size of the subsidy does not, by itself, dictate whether a resource would be economic in PJM's market without the subsidy. Depending on the resource's costs, and the revenue the resource receives in the PJM energy and ancillary service markets, the subsidy payments could effectively be surplus. Even then, however, it would be reasonable to assume that project developers, lenders, and investors took such expected revenue streams into account when structuring the project and assessing its risks, suggesting possible reliance on achievement of both PJM market revenues and the state subsidy revenues. Of course, it is also quite plausible to conclude that, at these subsidy levels, many resources do depend on those revenues, in combination with PJM market revenues, to be economic.

37. This concludes my affidavit.

Attachment 1
to
Affidavit of Dr. Anthony Giacomoni
Renewable Energy Requirements by PJM State

RENEWABLE ENERGY REQUIREMENT by STATE (%)

(including solar)

| | | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|----|-------------------------------------|------|-------|-------|-------|--------|--------|--------|--------|--------|--------|--------|--------|-------|
| NJ | Total | 6.5 | 7.406 | 8.297 | 9.214 | 10.388 | 12.527 | 13.757 | 14.899 | 15.985 | 18.025 | 19.965 | 21.909 | 23.85 |
| MD | Total | 4.51 | 5.525 | 7.5 | 9 | 10.7 | 12.8 | 13 | 15.2 | 15.6 | 18.3 | 20.4 | 25 | 25 |
| DE | Total | 3 | 4 | 5 | 7 | 8.5 | 10 | 11.5 | 13 | 14.5 | 16 | 17.5 | 19 | 20 |
| DC | Total | 5 | 5.5 | 6.5 | 7.5 | 9 | 10.5 | 12 | 13.5 | 15 | 16.5 | 18 | 20 | 20 |
| PA | Tier 1 only | 2 | 2.5 | 3 | 3.5 | 4 | 4.5 | 5 | 5.5 | 6 | 6.5 | 7 | 7.5 | 8 |
| WV | n/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| VA | Base year sales | 0 | 4 | 4 | 4 | 4 | 4 | 4 | 7 | 7 | 7 | 7 | 7 | 7 |
| NC | One-fourth of Total | 0 | 0 | 0 | 3 | 3 | 3 | 6 | 6 | 6 | 10 | 10 | 10 | 12.5 |
| OH | Total | 0.25 | 0.5 | 1 | 1.5 | 2 | 2.5 | 2.5 | 2.5 | 3.5 | 4.5 | 5.5 | 6.5 | 7.5 |
| | Goal - results in no new renewables | 0 | 0 | 0 | 0 | 4 | 4 | 4 | 4 | 4 | 4 | 7 | 7 | 7 |
| IN | Total | 0 | 0 | 0 | 2 | 3.3 | 5 | 10 | 10 | 10 | 10 | 12.5 | 12.5 | 15 |
| MI | n/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| KY | n/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TN | n/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IL | Total | 2 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11.5 | 13 | 14.5 | 16 | 17.5 |

ANNUAL NET ENERGY by STATE (GWh)

| | | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---------|--|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| NJ | | 83,447.61 | 82,617.58 | 81,607.00 | 81,379.00 | 82,956.74 | 79,333.74 | 80,167.61 | 79,899.00 | 81,054.00 | 77,694.00 | 77,142.00 | 76,181.00 | 75,536.00 |
| MD | | 71,671.17 | 71,473.23 | 71,210.40 | 70,660.19 | 72,229.39 | 69,619.14 | 70,349.47 | 71,948.18 | 71,159.12 | 70,370.66 | 70,255.10 | 70,209.53 | 70,038.24 |
| DE | | 11,457.14 | 11,506.93 | 11,499.11 | 11,559.50 | 11,632.45 | 11,439.05 | 11,590.92 | 11,655.88 | 11,652.22 | 11,488.13 | 11,491.18 | 11,491.18 | 11,466.17 |
| DC | | 9,715.34 | 9,648.50 | 9,570.60 | 9,450.60 | 9,742.78 | 9,330.12 | 9,416.36 | 9,617.10 | 9,581.70 | 9,470.40 | 9,452.70 | 9,429.00 | 9,393.00 |
| PA | | 15,315.17 | 56,859.30 | 157,360.20 | 158,152.24 | 160,395.82 | 157,789.91 | 159,859.22 | 160,868.16 | 161,351.12 | 160,713.48 | 161,115.60 | 161,014.92 | 161,125.40 |
| WV | | 34,464.79 | 34,948.04 | 35,136.58 | 34,979.35 | 35,000.80 | 34,501.64 | 34,710.69 | 35,524.37 | 35,279.93 | 35,241.61 | 35,467.49 | 35,725.16 | 35,953.86 |
| VA | | 113,201.41 | 114,618.11 | 114,268.57 | 114,379.43 | 115,835.26 | 115,849.73 | 117,770.15 | 117,374.60 | 118,364.74 | 117,440.09 | 118,728.02 | 119,278.34 | 119,863.43 |
| NC | | 4,704.54 | 4,765.52 | 4,738.40 | 4,748.45 | 4,828.46 | 4,854.26 | 4,950.88 | 4,904.10 | 4,968.30 | 4,926.60 | 4,988.70 | 5,014.20 | 5,042.10 |
| OH | | 75,859.93 | 76,438.93 | 113,731.09 | 162,290.57 | 161,891.69 | 159,212.54 | 160,344.63 | 163,862.85 | 164,104.43 | 163,370.56 | 163,820.63 | 163,816.20 | 163,738.74 |
| IN | | 23,827.41 | 24,054.89 | 24,244.22 | 24,170.41 | 24,060.19 | 23,518.77 | 23,566.42 | 24,039.79 | 23,772.87 | 23,597.11 | 23,685.79 | 23,700.12 | 23,709.50 |
| MI | | 4,711.63 | 4,756.62 | 4,794.06 | 4,779.46 | 4,757.66 | 4,650.60 | 4,660.03 | 4,753.63 | 4,700.85 | 4,666.10 | 4,686.63 | 4,686.47 | 4,688.32 |
| KY | | 6,461.67 | 6,523.36 | 6,574.70 | 11,155.91 | 21,304.21 | 21,711.32 | 21,901.19 | 22,165.24 | 22,106.76 | 22,129.20 | 22,196.06 | 22,238.50 | 22,261.02 |
| TN | | 2,153.89 | 2,174.45 | 2,191.57 | 2,184.90 | 2,174.93 | 2,125.99 | 2,130.30 | 2,173.09 | 2,148.96 | 2,133.07 | 2,141.09 | 2,142.38 | 2,143.23 |
| IL | | 100,824.62 | 102,084.00 | 102,058.00 | 101,128.00 | 104,057.76 | 101,299.87 | 102,703.81 | 102,549.00 | 104,593.00 | 103,484.00 | 103,832.00 | 103,711.00 | 103,923.00 |
| PJM RTO | | 557,816.31 | 602,468.83 | 738,984.50 | 791,018.00 | 810,868.15 | 795,236.68 | 804,121.68 | 811,335.00 | 814,838.00 | 806,725.00 | 809,000.00 | 808,638.00 | 808,882.00 |

RENEWABLE ENERGY REQUIREMENT by STATE (MWh)

| | | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|----|-------------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| NJ | Total | 5,424,094.65 | 6,118,657.85 | 6,770,932.79 | 7,498,261.06 | 8,617,545.82 | 9,938,137.33 | 11,028,658.55 | 11,904,152.01 | 12,956,481.90 | 14,004,343.50 | 15,401,400.30 | 16,690,495.29 | 18,015,336.00 |
| MD | Total | 3,232,369.58 | 3,948,896.10 | 5,340,780.00 | 6,359,417.10 | 7,728,545.16 | 8,911,249.68 | 9,145,431.20 | 10,936,123.36 | 11,100,822.72 | 12,877,830.78 | 14,332,040.40 | 17,552,382.50 | 17,509,560.00 |
| DE | Total | 343,714.19 | 460,277.05 | 574,955.50 | 809,165.00 | 988,757.95 | 1,143,904.50 | 1,332,955.60 | 1,515,264.40 | 1,689,571.90 | 1,838,100.80 | 2,010,956.50 | 2,183,324.20 | 2,293,234.00 |
| DC | Total | 485,766.91 | 530,667.28 | 622,089.00 | 708,795.00 | 876,850.10 | 979,662.94 | 1,129,962.92 | 1,298,308.50 | 1,437,255.00 | 1,562,616.00 | 1,701,486.00 | 1,885,800.00 | 1,878,600.00 |
| PA | Tier 1 only | 306,303.36 | 1,421,482.60 | 4,720,806.00 | 5,535,328.40 | 6,415,832.84 | 7,100,546.13 | 7,992,961.10 | 8,847,748.80 | 9,681,067.20 | 10,446,376.20 | 11,278,092.00 | 12,076,119.00 | 12,890,032.00 |
| WV | n/a | - | - | - | - | - | - | - | - | - | - | - | - | - |
| VA | Base year sales | - | 2,310,865.96 | 2,310,865.96 | 2,310,865.96 | 1,848,692.77 | 1,848,692.77 | 1,848,692.77 | 3,235,212.34 | 3,235,212.34 | 3,235,212.34 | 3,235,212.34 | 3,235,212.34 | 3,235,212.34 |
| NC | One-fourth of Total | - | - | - | 35,613.38 | 36,213.47 | 36,406.97 | 74,263.25 | 73,561.50 | 74,524.50 | 123,165.00 | 124,717.50 | 125,355.00 | 157,565.63 |
| OH | Total | 189,649.81 | 382,191.49 | 1,137,310.89 | 2,434,358.52 | 3,237,833.86 | 3,980,313.47 | 4,008,615.68 | 4,096,571.35 | 5,743,655.05 | 7,351,675.25 | 9,010,134.87 | 10,648,052.81 | 12,280,405.20 |
| | Goal - results in no new renewables | - | - | - | - | - | - | - | - | - | - | - | - | - |
| IN | Total | - | - | - | 95,589.20 | 157,002.93 | 232,530.21 | 466,002.67 | 475,363.00 | 470,085.00 | 466,609.50 | 585,453.75 | 585,808.13 | 703,248.00 |
| MI | n/a | - | - | - | - | - | - | - | - | - | - | - | - | - |
| KY | n/a | - | - | - | - | - | - | - | - | - | - | - | - | - |
| TN | n/a | - | - | - | - | - | - | - | - | - | - | - | - | - |
| IL | Total | 2,016,492.36 | 4,083,359.90 | 5,102,900.00 | 6,067,680.00 | 7,284,043.22 | 8,103,989.72 | 9,243,342.78 | 10,254,900.00 | 12,028,195.00 | 13,452,920.00 | 15,055,640.00 | 16,593,760.00 | 18,186,525.00 |

| | | | | | | | | | | | | | |
|--------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Total PJM RE Req'd (MWh) | 11,998,390.86 | 19,256,398.24 | 26,580,640.14 | 31,855,073.62 | 37,191,318.11 | 42,275,433.71 | 46,270,886.53 | 52,637,205.26 | 58,416,870.61 | 65,358,849.37 | 72,735,133.66 | 81,576,309.26 | 87,149,718.17 |
| PJM Load (GWh) | 557,816.31 | 602,468.83 | 738,984.50 | 791,018.00 | 810,868.15 | 795,236.68 | 804,121.68 | 811,335.00 | 814,838.00 | 806,725.00 | 809,000.00 | 808,638.00 | 808,882.00 |
| PJM Load | 557,816,309.33 | 602,468,828.17 | 738,984,500.00 | 791,018,000.00 | 810,868,148.92 | 795,236,683.96 | 804,121,682.84 | 811,335,000.00 | 814,838,000.00 | 806,725,000.00 | 809,000,000.00 | 808,638,000.00 | 808,882,000.00 |
| Percent of PJM Load | 2.15% | 3.20% | 3.60% | 4.03% | 4.59% | 5.32% | 5.75% | 6.49% | 7.17% | 8.10% | 8.99% | 10.09% | 10.77% |
| Capacity Equivlt (MW) | 1,369.68 | 2,198.22 | 3,034.32 | 3,636.42 | 4,245.58 | 4,825.96 | 5,282.06 | 6,008.81 | 6,668.59 | 7,461.06 | 8,303.10 | 9,312.36 | 9,948.60 |

This number represents the proportion (66%) of PJM-connected systems used to meet RPS compliance
This accounts for historic and prospective BitM generation and neighboring system resources used for compliance

| | | | | |
|----------|----------|----------|----------|----------|
| 4,441.28 | 4,969.06 | 5,529.86 | 6,202.03 | 6,625.77 |
|----------|----------|----------|----------|----------|

RENEWABLE ENERGY REQUIREMENT by STATE (%)

(including solar)

| | | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|----|-------------------------------------|-------|-------|-------|-------|------|-------|-------|-------|-------|-------|-------|-------|
| NJ | Total | 23.94 | 24.03 | 24.12 | 24.21 | 24.3 | 24.39 | 24.48 | 24.48 | 24.48 | 24.48 | 24.48 | 24.48 |
| MD | Total | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| DE | Total | 21 | 22 | 23 | 24 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| DC | Total | 20 | 20 | 23 | 26 | 29 | 32 | 35 | 38 | 42 | 46 | 50 | 50 |
| PA | Tier 1 only | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| WV | n/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| VA | Base year sales | 12 | 12 | 12 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| NC | One-fourth of Total | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 |
| OH | Total | 8.5 | 9.5 | 10.5 | 11.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 | 12.5 |
| | Goal - results in no new renewables | 7 | 7 | 7 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| IN | Total | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| MI | n/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| KY | n/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TN | n/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IL | Total | 19 | 20.5 | 22 | 23.5 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |

ANNUAL NET ENERGY by STATE (GWh)

| | | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---------|-------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| NJ | Total | 75,492.00 | 75,534.00 | 75,778.00 | 75,712.00 | 75,896.00 | 76,115.00 | 76,626.00 | 76,736.00 | 76,765.00 | 77,070.00 | 77,651.00 | 77,835.00 |
| MD | Total | 70,102.97 | 70,166.86 | 70,461.37 | 70,449.76 | 70,665.41 | 70,892.20 | 71,352.88 | 71,415.86 | 71,555.69 | 71,760.42 | 72,167.61 | 72,189.28 |
| DE | Total | 11,499.72 | 11,539.37 | 11,615.62 | 11,631.48 | 11,691.26 | 11,754.09 | 11,866.33 | 11,907.20 | 11,961.49 | 12,031.03 | 12,132.29 | 12,169.50 |
| DC | Total | 9,405.30 | 9,420.00 | 9,466.20 | 9,474.30 | 9,512.70 | 9,552.90 | 9,621.30 | 9,640.80 | 9,669.30 | 9,709.80 | 9,774.00 | 9,788.70 |
| PA | Total | 161,812.44 | 162,545.04 | 163,586.24 | 163,712.64 | 164,475.72 | 165,277.44 | 166,633.56 | 167,127.60 | 167,522.92 | 168,254.48 | 169,576.00 | 169,898.48 |
| WV | Total | 36,206.77 | 36,427.27 | 36,698.30 | 36,790.56 | 37,008.75 | 37,244.39 | 37,625.95 | 37,799.04 | 37,969.83 | 38,179.07 | 38,560.48 | 38,718.65 |
| VA | Total | 121,019.64 | 121,900.17 | 123,051.97 | 123,737.74 | 124,834.55 | 126,032.65 | 127,744.30 | 128,770.78 | 129,745.21 | 130,936.17 | 132,547.91 | 133,426.36 |
| NC | Total | 5,094.85 | 5,133.30 | 5,183.95 | 5,216.20 | 5,265.75 | 5,320.25 | 5,396.85 | 5,444.20 | 5,489.30 | 5,543.25 | 5,614.45 | 5,654.35 |
| OH | Total | 164,539.88 | 165,374.49 | 166,481.43 | 166,863.25 | 167,813.15 | 168,788.32 | 170,262.79 | 170,947.74 | 171,529.33 | 172,576.56 | 174,157.25 | 174,797.63 |
| IN | Total | 23,856.59 | 24,007.93 | 24,199.62 | 24,278.56 | 24,437.33 | 24,601.05 | 24,854.69 | 24,986.56 | 25,104.09 | 25,281.09 | 25,539.68 | 25,666.95 |
| MI | Total | 4,717.41 | 4,747.33 | 4,785.24 | 4,800.85 | 4,832.24 | 4,864.62 | 4,914.77 | 4,940.85 | 4,964.09 | 4,999.09 | 5,050.22 | 5,075.39 |
| KY | Total | 22,368.90 | 22,477.02 | 22,627.53 | 22,668.00 | 22,780.11 | 22,888.27 | 23,084.84 | 23,153.71 | 23,236.46 | 23,360.75 | 23,548.45 | 23,618.54 |
| TN | Total | 2,156.53 | 2,170.21 | 2,187.54 | 2,194.67 | 2,209.02 | 2,223.82 | 2,246.75 | 2,258.67 | 2,269.30 | 2,285.30 | 2,308.67 | 2,320.18 |
| IL | Total | 104,635.00 | 105,374.00 | 106,241.00 | 106,610.00 | 107,366.00 | 108,157.00 | 109,275.00 | 109,929.00 | 110,455.00 | 111,258.00 | 112,446.00 | 113,077.00 |
| PJM RTO | Total | 812,908.00 | 816,817.00 | 822,364.00 | 824,140.00 | 828,788.00 | 833,712.00 | 841,506.00 | 845,058.00 | 848,237.00 | 853,245.00 | 861,074.00 | 864,236.00 |

RENEWABLE ENERGY REQUIREMENT by STATE (MWh)

| | | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|----|-------------------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| NJ | Total | 18,072,784.80 | 18,150,820.20 | 18,277,653.60 | 18,329,875.20 | 18,442,728.00 | 18,564,448.50 | 18,758,044.80 | 18,784,972.80 | 18,792,072.00 | 18,866,736.00 | 19,008,964.80 | 19,054,008.00 |
| MD | Total | 17,525,742.50 | 17,541,715.00 | 17,615,342.50 | 17,612,440.00 | 17,666,352.50 | 17,723,050.00 | 17,838,220.00 | 17,853,965.00 | 17,888,922.50 | 17,940,105.00 | 18,041,902.50 | 18,047,320.00 |
| DE | Total | 2,414,941.20 | 2,538,661.40 | 2,671,592.60 | 2,791,555.20 | 2,922,815.00 | 2,938,522.50 | 2,966,582.50 | 2,976,800.00 | 2,990,372.50 | 3,007,757.50 | 3,033,072.50 | 3,042,375.00 |
| DC | Total | 1,881,060.00 | 1,884,000.00 | 2,177,226.00 | 2,463,318.00 | 2,758,683.00 | 3,056,928.00 | 3,367,455.00 | 3,663,504.00 | 4,061,106.00 | 4,466,508.00 | 4,887,000.00 | 4,894,350.00 |
| PA | Tier 1 only | 12,944,995.20 | 13,003,603.20 | 13,086,899.20 | 13,097,011.20 | 13,158,057.60 | 13,222,195.20 | 13,330,684.80 | 13,370,208.00 | 13,401,833.60 | 13,460,358.40 | 13,566,080.00 | 13,591,878.40 |
| WV | n/a | - | - | - | - | - | - | - | - | - | - | - | - |
| VA | Base year sales | 5,546,078.30 | 5,546,078.30 | 5,546,078.30 | 6,932,597.88 | 6,932,597.88 | 6,932,597.88 | 6,932,597.88 | 6,932,597.88 | 6,932,597.88 | 6,932,597.88 | 6,932,597.88 | 6,932,597.88 |
| NC | One-fourth of Total | 159,214.06 | 160,415.63 | 161,998.44 | 163,006.25 | 164,554.69 | 166,257.81 | 168,651.56 | 170,131.25 | 171,540.63 | 173,226.56 | 175,451.56 | 176,698.44 |
| OH | Total | 13,985,889.72 | 15,710,576.93 | 17,480,550.47 | 19,189,273.87 | 20,976,644.00 | 21,098,539.63 | 21,282,848.25 | 21,368,467.63 | 21,441,166.63 | 21,572,070.38 | 21,769,655.75 | 21,849,704.13 |
| | Goal - results in no new renewables | - | - | - | - | - | - | - | - | - | - | - | - |
| IN | Total | 707,610.75 | 712,099.50 | 717,785.25 | 720,126.75 | 724,836.00 | 729,692.25 | 737,215.50 | 741,126.75 | 744,612.75 | 749,862.75 | 757,533.00 | 761,307.75 |
| MI | n/a | - | - | - | - | - | - | - | - | - | - | - | - |
| KY | n/a | - | - | - | - | - | - | - | - | - | - | - | - |
| TN | n/a | - | - | - | - | - | - | - | - | - | - | - | - |
| IL | Total | 19,880,650.00 | 21,601,670.00 | 23,373,020.00 | 25,053,350.00 | 26,841,500.00 | 27,039,250.00 | 27,318,750.00 | 27,482,250.00 | 27,613,750.00 | 27,814,500.00 | 28,111,500.00 | 28,269,250.00 |

| | | | | | | | | | | | | |
|--------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Total PJM RE Req'd (MWh) | 93,118,966.53 | 96,849,640.16 | 101,108,146.36 | 106,352,554.35 | 110,588,768.67 | 111,471,481.77 | 112,701,050.29 | 113,344,023.31 | 114,037,974.48 | 114,983,722.47 | 116,283,757.99 | 116,619,489.59 |
| PJM Load (GWh) | 812,908.00 | 816,817.00 | 822,364.00 | 824,140.00 | 828,788.00 | 833,712.00 | 841,506.00 | 845,058.00 | 848,237.00 | 853,245.00 | 861,074.00 | 864,236.00 |
| PJM Load | 812,908,000.00 | 816,817,000.00 | 822,364,000.00 | 824,140,000.00 | 828,788,000.00 | 833,712,000.00 | 841,506,000.00 | 845,058,000.00 | 848,237,000.00 | 853,245,000.00 | 861,074,000.00 | 864,236,000.00 |
| Percent of PJM Load | 11.46% | 11.86% | 12.29% | 12.90% | 13.34% | 13.37% | 13.39% | 13.41% | 13.44% | 13.48% | 13.50% | 13.49% |
| Capacity Equivlt (MW) | 10,630.02 | 11,055.89 | 11,542.03 | 12,140.70 | 12,624.29 | 12,725.05 | 12,865.42 | 12,938.82 | 13,018.03 | 13,126.00 | 13,274.40 | 13,312.73 |

This number represents the proportion (66%) of PJM-connected systems used to meet RPS compliance

| | | | | | | | | | | | | |
|--|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|
| | 7,079.59 | 7,363.23 | 7,686.99 | 8,085.71 | 8,407.78 | 8,474.89 | 8,568.37 | 8,617.25 | 8,670.01 | 8,741.91 | 8,840.75 | 8,866.28 |
|--|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|

This accounts for historic and prospective BitM generation and neighboring system resources used for compliance

Attachment 2
to
Affidavit of Dr. Anthony Giacomoni
State Subsidies on a \$-MW-day Basis

| State Subsidies on a \$/MW/day Basis | State Action | |
|--------------------------------------|-------------------------------------|-------------------------|
| | 1 | 6 |
| | State Renewable Portfolio Standards | Zero Emissions Credits* |
| Example 1 | | |
| Type of Generation | Solar (NJ) | Nuclear (IL) |
| Capacity Factor, % | 17.7% | 93% |
| UCAP Credit per MW of ICAP** | 38% | 98.4% |
| Energy Output, MWh/1 MW UCAP | 4,080 | 8,279 |
| Credit Rate, \$/MWh | \$230.33 | \$11.69 |
| Annual Credit, \$/MW-year | \$939,819 | \$96,797 |
| Credit, \$/MW-day | \$2,575 | \$265 |
| Example 2 | | |
| Type of Generation | Wind (NJ) | |
| Capacity Factor, % | 28% | |
| UCAP Credit per MW of ICAP** | 15% | |
| Energy Output, MWh/1 MW UCAP | 16,352 | |
| Credit Rate, \$/MWh | \$5.58 | |
| Annual Credit, \$/MW-year | \$91,244 | |
| Credit, \$/MW-day | \$250 | |
| Example 3 | | |
| Type of Generation | Solar (OH) | |
| Capacity Factor, % | 17.7% | |
| UCAP Credit per MW of ICAP** | 38% | |
| Energy Output, MWh/1 MW UCAP | 4,080 | |
| Credit Rate, \$/MWh | \$5.31 | |
| Annual Credit, \$/MW-year | \$21,666 | |
| Credit, \$/MW-day | \$59 | |
| Example 4 | | |
| Type of Generation | Wind (OH) | |
| Capacity Factor, % | 28% | |
| UCAP Credit per MW of ICAP** | 15% | |
| Energy Output, MWh/1 MW UCAP | 16,352 | |
| Credit Rate, \$/MWh | \$4.51 | |
| Annual Credit, \$/MW-year | \$73,748 | |
| Credit, \$/MW-day | \$202 | |
| Example 5 | | |
| Type of Generation | Solar (DC) | |
| Capacity Factor, % | 17.7% | |
| UCAP Credit per MW of ICAP** | 38% | |
| Energy Output, MWh/1 MW UCAP | 4,080 | |
| Credit Rate, \$/MWh | \$425.00 | |
| Annual Credit, \$/MW-year | \$1,734,134 | |
| Credit, \$/MW-day | \$4,751 | |

| State Subsidies on a \$/MW/day Basis | State Action | |
|--------------------------------------|-------------------------------------|-------------------------|
| | 1 | 6 |
| | State Renewable Portfolio Standards | Zero Emissions Credits* |
| Example 6 | | |
| Type of Generation | Wind (DC) | |
| Capacity Factor, % | 28% | |
| UCAP Credit per MW of ICAP** | 15% | |
| Energy Output, MWh/1 MW UCAP | 16,352 | |
| Credit Rate, \$/MWh | \$2.98 | |
| Annual Credit, \$/MW-year | \$48,729 | |
| Credit, \$/MW-day | \$134 | |
| Example 7 | | |
| Type of Generation | Wind (DE) | |
| Capacity Factor, % | 28% | |
| UCAP Credit per MW of ICAP** | 15% | |
| Energy Output, MWh/1 MW UCAP | 16,352 | |
| Credit Rate, \$/MWh | \$5.65 | |
| Annual Credit, \$/MW-year | \$92,389 | |
| Credit, \$/MW-day | \$253 | |
| Example 8 | | |
| Type of Generation | Solar (MD) | |
| Capacity Factor, % | 17.7% | |
| UCAP Credit per MW of ICAP** | 38% | |
| Energy Output, MWh/1 MW UCAP | 4,080 | |
| Credit Rate, \$/MWh | \$11.42 | |
| Annual Credit, \$/MW-year | \$46,597 | |
| Credit, \$/MW-day | \$128 | |
| Example 9 | | |
| Type of Generation | Wind (MD) | |
| Capacity Factor, % | 28% | |
| UCAP Credit per MW of ICAP** | 15% | |
| Energy Output, MWh/1 MW UCAP | 16,352 | |
| Credit Rate, \$/MWh | \$5.42 | |
| Annual Credit, \$/MW-year | \$88,628 | |
| Credit, \$/MW-day | \$243 | |

*Credit rate based on a cost cap of \$235 million instead of estimated price of \$14.88/MWh.

**Based on PJM 2012-2016 weighted class average EFORD for traditional units and 2017 class average capacity factors for wind and solar resources.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

)

Docket No. ER18-__-000

Anthony Giacomoni, being first duly sworn, deposes and states that he is the Anthony Giacomoni referred to in the foregoing document entitled "Affidavit of Dr. Anthony Giacomoni," 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.

Anthony Giacomoni

Subscribed and sworn to before me, the undersigned notary public, this 6th day of April, 2018.

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Linda Spreeman, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Nov. 17, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Linda Spreeman

Notary Public

My Commission expires: November 17, 2019



FERC rendition of the electronically filed tariff records in Docket No. ER18-01314-000

Filing Data:

CID: C000030

Filing Title: Revisions to Address Impacts of State Public Policies on the PJM Capacity Market

Company Filing Identifier: 3879

Type of Filing Code: 10

Associated Filing Identifier:

Tariff Title: Intra-PJM Tariffs

Tariff ID: 23

Payment Confirmation:

Suspension Motion:

Tariff Record Data:

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

A-B, OATT Definitions - A - B, 11.0.0, A

Record Narrative Name: Definitions - A - B

Tariff Record ID: 4

Tariff Record Collation Value: 3145309 Tariff Record Parent Identifier: 3

Proposed Date: 2019-01-04

Priority Order: 500

Record Change Type: CHANGE

Record Content Type: 1

Associated Filing Identifier:

Definitions – A - B

Abnormal Condition:

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, sections 1.9.2 or 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix.

Actionable Subsidy Reference Price:

“Actionable Subsidy Reference Price” shall have the meaning provided in Tariff, Attachment DD, section 5.14(j).

Additional Day-ahead Scheduling Reserves Requirement:

“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead

Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

Affected System:

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

”Affiliate” shall mean any two or more entities, one of which controls the other or that are under common control. “Control” shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider’s Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

“Annual Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

“Annual Resource” shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

Annual Resource Price Adder:

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

Annual Revenue Rate:

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable

Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H-” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix.

Authorized Government Agency:

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Balancing Ratio:

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Demand Resource Constraint:

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the

PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Resource:

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint

is binding.

Base Day-ahead Scheduling Reserves Requirement:

“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

Base Load Generation Resource

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Demand Resource:

“Batch Load Demand Resource” shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource; or (ii) in an

hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

“Black Start Service” shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Breach:

“Breach” shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

“Breaching Party” shall mean a party that is in Breach of Tariff, Part IV or Part VI and/or an agreement entered into thereunder.

Business Day:

“Business Day” shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

C-D, OATT Definitions - C-D, 13.0.0, A

Record Narrative Name: Definitions - C-D

Tariff Record ID: 5

Tariff Record Collation Value: 3860412 Tariff Record Parent Identifier: 3

Proposed Date: 2019-01-04

Priority Order: 550

Record Change Type: CHANGE

Record Content Type: 1

Associated Filing Identifier:

Definitions – C-D

Canadian Guaranty:

“Canadian Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

“Cancellation Costs” shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or *Tariff*, Part VI.

Capacity:

“Capacity” shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

“Capacity Emergency Transfer Limit” or “CETL” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:

“Capacity Emergency Transfer Objective” or “CETO” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Export Transmission Customer:

“Capacity Export Transmission Customer” shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

“Capacity Import Limit” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

“Capacity Interconnection Rights” shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

“Capacity Market Buyer” shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

“Capacity Market Seller” shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:

“Capacity Performance Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource Clearing Price:

“Capacity Resource Clearing Price” shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Resource with Actionable Subsidy:

“Capacity Resource with Actionable Subsidy” or “Capacity Resources with Actionable Subsidies” shall have the meaning provided in Tariff, Attachment DD, section 5.14(j).

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

Capacity Transfer Right:

“Capacity Transfer Right” shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational

Delivery Area.

Capacity Transmission Injection Rights:

“Capacity Transmission Injection Rights” shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

“Collateral” shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

“Collateral Call” shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Commencement Date:

“Commencement Date” shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Commission:

“Commission” shall mean the Federal Energy Regulatory Commission or FERC.

Committed Offer:

The “Committed Offer” shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

Completed Application:

“Completed Application” shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction, *or the same locational price separation in the Final Incremental Auction.*

Conditional Incremental Auction:

“Conditional Incremental Auction” shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

CONE Area:

“CONE Area” shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

“Confidential Information” shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party’s technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, *section 2*.

Consolidated Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement” shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

Constructing Entity:

“Constructing Entity” shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection

Facilities.

Construction Party:

“Construction Party” shall mean a party to a Construction Service Agreement. “Construction Parties” shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

“Controllable A.C. Merchant Transmission Facilities” shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and *Tariff*, Part VI.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell

energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.13*.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.13*.

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:

“Cost of New Entry” or “CONE” shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, *Tariff*, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own .

Credit Available for Export Transactions:

“Credit Available for Export Transactions” shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant’s Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

“Credit Available for Virtual Transactions” shall mean the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

“Credit Breach” shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:

“Credit-Limited Offer” shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Score:

“Credit Score” shall mean a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:

“CTS Enabled Interface” shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling (“CTS”). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., *Schedule A* (PJM Rate Schedule FERC No. 45).

CTS Interface Bid:

“CTS Interface Bid” shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.13*.

Curtailment:

“Curtailment” shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

“Curtailment Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV, *subparts A*.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

“Customer Interconnection Facilities” shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer’s side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

“Daily Deficiency Rate” shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, sections 7, 8, 9, or 13.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

“Day-ahead Congestion Price” shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10*.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions and import transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions and Export Transactions.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-ahead Scheduling Reserves:

“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the Reliability *First* Corporation and SERC.

Day-ahead Scheduling Reserves Market:

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10*.

Day-ahead Scheduling Reserves Requirement:

“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:

“Day-ahead Scheduling Reserves Resources” shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

“Day-ahead System Energy Price” shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

“Deactivation” shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

“Deactivation Avoidable Cost Credit” shall mean the credit paid to Generation Owners pursuant to Tariff, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff,

section 115 .

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, , or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10.1B*.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10.1B*.

Demand Resource:

“Demand Resource” shall mean a resource with the capability to provide a reduction in demand.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or (“DR Factor”) shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

“Designated Agent” shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

“Designated Entity” shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

“Direct Assignment Facilities” shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Dispatch Rate:

“Dispatch Rate” shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

“Dynamic Transfer” shall have the same meaning provided in the Operating Agreement.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

C-D, OATT Definitions - C-D, 13.0.1, B

Record Narrative Name: Definitions - C-D

Tariff Record ID: 5

Tariff Record Collation Value: 3860412 Tariff Record Parent Identifier: 3

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Priority Order: 500

Record Change Type: CHANGE

Record Content Type: 1

Associated Filing Identifier:

Definitions – C-D

Canadian Guaranty:

“Canadian Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

“Cancellation Costs” shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or *Tariff*, Part VI.

Capacity:

“Capacity” shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

“Capacity Emergency Transfer Limit” or “CETL” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:

“Capacity Emergency Transfer Objective” or “CETO” shall have the meaning provided in the

Reliability Assurance Agreement.

Capacity Export Transmission Customer:

“Capacity Export Transmission Customer” shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

“Capacity Import Limit” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

“Capacity Interconnection Rights” shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

“Capacity Market Buyer” shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

“Capacity Market Seller” shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:

“Capacity Performance Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource Clearing Price:

“Capacity Resource Clearing Price” shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Resource with Actionable Subsidy:

“Capacity Resource with Actionable Subsidy” shall have the meaning provided in Tariff, Attachment DD, section 5.14(h)(2).

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

Capacity Transfer Right:

“Capacity Transfer Right” shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

Capacity Transmission Injection Rights:

“Capacity Transmission Injection Rights” shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

“Collateral” shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

“Collateral Call” shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Commencement Date:

“Commencement Date” shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Commission:

“Commission” shall mean the Federal Energy Regulatory Commission or FERC.

Committed Offer:

The “Committed Offer” shall mean 1) for pool-scheduled resources, an offer on which a resource

was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

Completed Application:

“Completed Application” shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction, *or the same locational price separation in the Final Incremental Auction.*

Conditional Incremental Auction:

“Conditional Incremental Auction” shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

CONE Area:

“CONE Area” shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

“Confidential Information” shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party’s technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an

Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, *section 2*.

Consolidated Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement” shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

Constructing Entity:

“Constructing Entity” shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

“Construction Party” shall mean a party to a Construction Service Agreement. “Construction Parties” shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of

Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

“Controllable A.C. Merchant Transmission Facilities” shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and *Tariff*, Part VI.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.13*.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.13*.

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:

“Cost of New Entry” or “CONE” shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, *Tariff*, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own .

Credit Available for Export Transactions:

“Credit Available for Export Transactions” shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

“Credit Available for Virtual Transactions” shall mean the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

“Credit Breach” shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:

“Credit-Limited Offer” shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Score:

“Credit Score” shall mean a composite numerical score scaled from 0-100 as calculated by

PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:

“CTS Enabled Interface” shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling (“CTS”). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., *Schedule A* (PJM Rate Schedule FERC No. 45).

CTS Interface Bid:

“CTS Interface Bid” shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.13*.

Curtailement:

“Curtailement” shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailement Service Provider:

“Curtailement Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV, *subparts A*.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

“Customer Interconnection Facilities” shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer’s side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

“Daily Deficiency Rate” shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, sections 7, 8, 9, or 13.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

“Day-ahead Congestion Price” shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10*.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions and import transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to

the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions and Export Transactions.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-ahead Scheduling Reserves:

“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the Reliability *First* Corporation and SERC.

Day-ahead Scheduling Reserves Market:

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10*.

Day-ahead Scheduling Reserves Requirement:

“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:

“Day-ahead Scheduling Reserves Resources” shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

“Day-ahead System Energy Price” shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

“Deactivation” shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

“Deactivation Avoidable Cost Credit” shall mean the credit paid to Generation Owners pursuant to Tariff, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, section 115 .

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, , or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10.1B*.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10.1B*.

Demand Resource:

“Demand Resource” shall mean a resource with the capability to provide a reduction in demand.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or (“DR Factor”) shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

“Designated Agent” shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

“Designated Entity” shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

“Direct Assignment Facilities” shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Dispatch Rate:

“Dispatch Rate” shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

“Dynamic Transfer” shall have the same meaning provided in the Operating Agreement.

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Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced

Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner’s system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Entity (LSE):

“Load Serving Entity” or “LSE” shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the *Real-time Settlement Interval* real-time Locational Marginal Price at the resource’s bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the *Real-time Settlement Interval* integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

“Locational Deliverability Area” or “LDA” shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area’s reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

“Locational Deliverability Area Reliability Requirement” shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

“Locational Price Adder” shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

“Locational Reliability Charge” shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

“Locational UCAP” shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

Long-lead Project:

“Long-lead Project” shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the organization that is responsible for implementing this Plan, including the Market Monitor.

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on

behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Attachment M of the Tariff, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD, section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request

with a later Queue Position.

Material Subsidy:

“Material Subsidy” shall mean: (1) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource. A Material Subsidy shall not include (3) 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; (4) 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 (5) 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.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the

Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System

or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified on Attachment T to the Tariff, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Section 36 of the Tariff, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

“Minimum Extended Summer Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

“Minimum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

“Minimum Participation Requirements” shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period

after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

"Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

"Native Load Customers" shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner's system to meet the reliable electric needs of such customers.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts Part II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Article I of the Reliability Assurance Agreement.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company

and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Service Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each *six*-month period ending on April 30 and October 31 of each year shall collectively comprise a New Services Queue.

New Services Queue Closing Date:

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the *six*-month period ending on such date.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

“Nominated Energy Efficiency Value” shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Attachment DD, § 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
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Record Narrative Name: Definitions - L - M - N
Tariff Record ID: 9
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Proposed Date: 2019-01-04
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Definitions – L – M - N

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed

generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and

published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the

interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the *Real-time Settlement Interval* real-time Locational Marginal Price at the resource’s bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the *Real-time Settlement Interval* integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

“Locational Deliverability Area” or “LDA” shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area’s reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

“Locational Deliverability Area Reliability Requirement” shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

“Locational Price Adder” shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

“Locational Reliability Charge” shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

“Locational UCAP” shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

Long-lead Project:

“Long-lead Project” shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include

expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the organization that is responsible for implementing this Plan, including the Market Monitor.

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Attachment M of the Tariff, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

“Material Subsidy:

“Material Subsidy” shall mean: (1) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource. A Material Subsidy shall not include (3) 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; (4) 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 (5) 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.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified on Attachment T to the Tariff, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Section 36 of the Tariff, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

“Minimum Extended Summer Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff,

Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

“Minimum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

“Minimum Participation Requirements” shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts Part II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Article I of the Reliability Assurance Agreement.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Service Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each *six*-month period ending on April 30 and October 31 of each year shall collectively comprise a New Services Queue.

New Services Queue Closing Date:

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the *six*-month period ending on such date.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand

Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

“Nominated Energy Efficiency Value” shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Attachment DD, § 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel

supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

Non-Retail Behind The Meter Generation:

"Non-Retail Behind The Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix.

Non-Zone Network Load:

"Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
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ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this Section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this Section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Section 18.17 of the PJM Operating Agreement.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of Section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this Section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the PJM Market Monitor using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the PJM Market Monitor from a third party which is not, to the Office of the Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this Section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. Disclosure to FERC and CFTC:

1. Notwithstanding anything in this Section I to the contrary, if the FERC, the Commodity Futures Trading Commission (“CFTC”) or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing Section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC’s Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in Section I.B.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this Section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Schedule 10A. Upon receipt of the Authorized Commission’s Certification, the FERC shall provide public notice of the Authorized Commission’s filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission’s Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a

response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this Section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The

Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of Section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding Section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information

Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an

Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this Section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this Section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this Section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in Section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in Section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. Market Monitoring:

1. Subject to the requirements of Section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G

Zone to the New York Independent System Operator, Inc. (“New York ISO”), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that the Office of the Interconnection or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of the Office of the Interconnection and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member’s confidential information pursuant to Section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under Section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this Section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Section 6.4.2 of Schedule 1 of the Operating Agreement) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Schedule 2 of the Operating Agreement.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Section 6.4.2 of Schedule 1 of the Operating Agreement is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an

evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Section 6.4 of Schedule 1 of the Operating Agreement. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. Minimum Generator Operating Parameters:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Section 6.6(c) of Schedule 1 of the Operating Agreement. The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Section 6.6 of Schedule 1 of the Operating Agreement and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the

Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Section 6.6 of Attachment DD.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to Section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORD to be included in a Sell Offer applicable to each resource pursuant to Section 6.6(b) of Attachment DD. If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORD to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORD if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety

(90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Section 5.6.6 of Attachment DD of the PJM Tariff, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in Section II.C.4 above, or (iii) a maximum EFORD that the Market Monitoring Unit believes is inconsistent with the maximum level determined under Section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Section 6.6 of Attachment DD.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Section 6.6 of Attachment DD, for generation resources for

which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Section 6.6(g) of Attachment DD, to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Section 6.6(i) of Attachment DD, and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. Repricing Sell Offers for Capacity Resources with Actionable Subsidy:

1. Each Capacity Market Seller that submits documentation for the determination an Actionable Subsidy Reference Price pursuant to the requirements set forth in Tariff, Attachment DD, section 5.14(j)(4), the Market Monitoring Unit shall review the documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than forty-five (45) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer the Market Monitoring Unit's determination of whether the requested Actionable Subsidy Reference Price is acceptable.

2. All information submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

D-1. Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy:

1. In the event that the Market Monitoring Unit reasonably believes that a certification of a Capacity Resource's status contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource would be a Capacity Resource with Actionable Subsidy had the certification not contained such misrepresentations or omissions, then it shall notify the Office of the Interconnection and Capacity Market Seller of its findings and provide the Office of the Interconnection with all of the data and documentation supporting its findings, and may take any other action required or permitted under Tariff, Attachment M.

E. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Section 6.7(d) of Attachment DD, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market

Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Section 6.4(a) of Attachment DD.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. Data Submission:

Pursuant to Section 6.7 of Attachment DD, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Section 6.7(c) of Attachment DD and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Section 6.7 of Attachment DD, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the

Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in section 6.7(d) of Attachment DD.

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Section 6.8(d) of Attachment DD, and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Section 6.7(d)(ii) of Attachment DD. The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Schedule 6A of the PJM Tariff and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring

Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Part V of the PJM Tariff from the Office of the Interconnection forwarded pursuant to Section 113.1 of the PJM Tariff, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Sections 114 and 119 of Part V of the PJM Tariff.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement, discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement.

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Section 5.2.1(b) of Schedule 1 of the Operating Agreement, including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an

entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

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ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this Section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of

time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this Section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Section 18.17 of the PJM Operating Agreement.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of Section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this Section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the PJM Market Monitor using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the PJM Market Monitor from a third party which is not, to the Office of the Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this Section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. Disclosure to FERC and CFTC:

1. Notwithstanding anything in this Section I to the contrary, if the FERC, the Commodity Futures Trading Commission (“CFTC”) or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing Section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC’s Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in Section I.B.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this Section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Schedule 10A. Upon receipt of the Authorized Commission’s Certification, the FERC shall provide public notice of the Authorized Commission’s filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission’s Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC’s consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission’s Certification

within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this Section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any

confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of Section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding Section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any

conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a “fast track” complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission’s ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission’s Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that “exceptional circumstances,” as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute “exceptional circumstances” as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as “Confidential,” challenging such designation. Any complaints filed at FERC objecting to the designation of information as “Confidential” shall be designated by the party as a “fast track” complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit “Confidential” status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with “publicly available” not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this Section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this Section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected

Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this Section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in Section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in Section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. Market Monitoring:

1. Subject to the requirements of Section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that the Office of the Interconnection or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of the Office of the Interconnection and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member's confidential information pursuant to Section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under Section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this Section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Section 6.4.2 of Schedule 1 of the Operating Agreement) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Schedule 2 of the Operating Agreement.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Section 6.4.2 of Schedule 1 of the Operating Agreement is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Section 6.4 of Schedule 1 of the Operating Agreement. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. Minimum Generator Operating Parameters:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the “Parameter Limited Schedule Matrix” to be included in Section 6.6(c) of Schedule 1 of the Operating Agreement. The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Section 6.6 of Schedule 1 of the Operating Agreement and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit’s determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Section 6.6 of Attachment DD.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to Section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORD to be included in a Sell Offer applicable to each resource pursuant to Section 6.6(b) of Attachment DD. If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORD to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORD if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource

beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Section 5.6.6 of Attachment DD of the PJM Tariff, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in Section II.C.4 above, or (iii) a maximum EFORD that the Market Monitoring Unit believes is inconsistent with the maximum level determined under Section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Section 6.6 of Attachment DD.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Section 6.6 of Attachment DD, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Section 6.6(g) of Attachment DD, to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Section 6.6(i) of Attachment DD, and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. Unit Specific Minimum Sell Offers:

1. If a Capacity Market Seller timely submits an exemption or exception request under Tariff, Attachment DD, section 5.14(h) of Attachment DD, with all of the required supporting documentation as, the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than forty-five (45) days after receipt of the exemption or exception request its determination whether it believes the requested exemption or exception should be granted in accordance with the standards and criteria set forth in Tariff, Attachment DD, section 5.14(h). If the Market Monitoring Unit determines that the Sell Offer proposed in a Unit-Specific Exception request raises market power concerns, it shall advise the Capacity Market Seller of the minimum Sell Offer in the relevant auction that would not raise market power concerns, with such calculation based on the data and documentation received, by no later than forty-five (45) days after receipt of the request.
2. All information submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.
3. In the event that the Market Monitoring Unit reasonably believes that a request for a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or a Renewable Portfolio Standard Exemption that has been granted contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller would not have been eligible for the exemption from being a Capacity Resource with Actionable Subsidy for that Capacity Resource had the request not contained such misrepresentations or omissions, then it shall notify the Office of the Interconnection and Capacity Market Seller of its findings and provide the Office of the Interconnection with all of the data and documentation supporting its findings, and may take any other action required or permitted under Attachment M.

E. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Section 6.7(d) of Attachment DD, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.
2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.
3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring

Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Section 6.4(a) of Attachment DD.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. Data Submission:

Pursuant to Section 6.7 of Attachment DD, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Section 6.7(c) of Attachment DD and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Section 6.7 of Attachment DD, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in section 6.7(d) of Attachment DD.

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Section 6.8(d) of Attachment DD, and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Section 6.7(d)(ii) of Attachment DD. The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Schedule 6A of the PJM Tariff and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Part V of the PJM Tariff from the Office of the Interconnection forwarded pursuant to Section 113.1 of the PJM Tariff, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Sections 114 and 119 of Part V of the PJM Tariff.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement, discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement.

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Section 5.2.1(b) of Schedule 1 of the Operating Agreement, including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may

exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

ATTACHMENT DD, OATT ATTACHMENT DD, 1.0.0, A

Record Narrative Name: ATTACHMENT DD

Reliability Pricing Model

Tariff Record ID: 1132

Tariff Record Collation Value: 653889039 Tariff Record Parent Identifier: 357

Proposed Date: 2018-06-30

Priority Order: 550

Record Change Type: CHANGE

Record Content Type: 1

Associated Filing Identifier:

ATTACHMENT DD

Reliability Pricing Model

References to section numbers in this Attachment DD refer to sections of this Attachment DD, unless otherwise specified.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

ATTACHMENT DD, OATT ATTACHMENT DD, 1.0.1, B
Record Narrative Name: ATTACHMENT DD

Reliability Pricing Model
Tariff Record ID: 1132
Tariff Record Collation Value: 653889039 Tariff Record Parent Identifier: 357
Proposed Date: 2018-06-30
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT DD

Reliability Pricing Model

References to section numbers in this Attachment DD refer to sections of this Attachment DD, unless otherwise specified.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
ATTACHMENT DD.5.2, OATT ATTACHMENT DD.5.2 Nomination of Self Supplied Capacity, 4.0.0, A
Record Narrative Name: 5.2 Nomination of Self Supplied Capacity Resources
Tariff Record ID: 1144
Tariff Record Collation Value: 658894760 Tariff Record Parent Identifier: 1142
Proposed Date: 2019-01-04
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the repricing provisions of section 5.14(j). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJM Settlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT DD.5.11, OATT ATTACHMENT DD.5.11 Posting of Information Relevant to t, 15.0.0, A
Record Narrative Name: OATT ATT DD.5.11 Posting of Information Relevant to the RPM Auctions
Tariff Record ID: 1154

Tariff Record Collation Value: 665688238 Tariff Record Parent Identifier: 1142
 Proposed Date: 2019-01-04
 Priority Order: 550
 Record Change Type: CHANGE
 Record Content Type: 1
 Associated Filing Identifier:

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, *Final* and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third *Incremental Auction and Final* Incremental Auction, *as applicable*, for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity of Capacity Resources with Actionable Subsidies; the aggregate megawatt quantity cleared in the RPM Auction of Capacity Resources with Actionable Subsidies; and the aggregate megawatt quantity of Capacity Resources with Actionable Subsidies for any LDA other than those specified in the preceding clause if the LDA has four (4) or more generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh Business Day

following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

OATT ATT DD.5.11, OATT ATTACHMENT DD.5.11 Posting of Information Relevant to t, 15.0.1, B

Record Narrative Name: OATT ATT DD.5.11 Posting of Information Relevant to the RPM Auctions

Tariff Record ID: 1154

Tariff Record Collation Value: 665688238 Tariff Record Parent Identifier: 1142

Proposed Date: 2019-01-04

Priority Order: 500

Record Change Type: CHANGE

Record Content Type: 1

Associated Filing Identifier:

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability

Area for which PJM is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under *Tariff, Attachment DD*, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) In addition to the information required to be posted by subsection (a), PJM will post for a Delivery Year, at least sixty (60) days prior to conducting the Base Residual Auction for such Delivery Year, the aggregate megawatt quantity of, for the PJM Region, all Self-Supply, Competitive, Public Entity, and RPS Exemption requests under *Tariff, Attachment DD*, section 5.14(h) and such exemptions granted in each such category, and to the extent PJM has made any such determination, notice that PJM has determined that one or more state-sponsored or state-mandated procurement processes is Competitive and Non-Discriminatory pursuant to *Tariff, Attachment DD*, section 5.14(h).

c) The information listed in (a) will be posted and applicable for the First, Second, Third, *Final* and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this *Tariff*.

d) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

e) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third *Incremental Auction and Final* Incremental Auction, *as applicable*, for such Delivery Year.

f) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results

shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity requested and granted in the Self-Supply Exemption, Competitive Exemption, Public Entity Exemption, and RPS Exemption categories in the EMAAC, MAAC, and Rest of RTO LDAs/regions; the aggregate megawatt quantity cleared in the RPM Auction for the Self-Supply Exemption, Competitive Exemption, Public Entity Exemption, and Renewable Portfolio Standard Exemption categories; and the aggregate megawatt quantity of the Self-Supply Exemption, Competitive Entry Exemption, Public Power Entity Exemption, and RPS Exemption requested and granted for any LDA other than those specified in the preceding clause if the LDA has more than four generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
 OATT ATT DD.5.14, OATT ATTACHMENT DD.5.14 Clearing Prices and Charges, 25.0.0, A
 Record Narrative Name: OATT ATTACHMENT DD.5.14 Clearing Prices and Charges
 Tariff Record ID: 1158
 Tariff Record Collation Value: 668906202 Tariff Record Parent Identifier: 1142
 Proposed Date: 2019-01-04
 Priority Order: 550
 Record Change Type: CHANGE
 Record Content Type: 1
 Associated Filing Identifier:

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as

necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm; provided, however, for each RPM Base Residual Auction conducted for the 2022/2023 Delivery Year and subsequent Delivery Years, once the optimization algorithm clears in any Delivery Year, for the PJM Region, more than 5,000 megawatts of unforced capacity from Capacity Resources with Actionable Subsidy, or for any modeled LDA, a megawatt quantity of Capacity Resources with Actionable Subsidy equal to or exceeding 3.5 percent of that LDA's Reliability Requirement, then the Capacity Resource Clearing Prices for the PJM Region will be determined in accordance with subsection 5.14(j). 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.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

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. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such

Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORD).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal

offer, in accordance with sections 5.12(a) and 5.14(a).

- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or
- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and
- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and
- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to

establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. 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 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. 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) [Reserved for Future Use]

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.

j) Repricing to Accommodate Capacity Resources with Actionable Subsidies.

(1) General Rule.

(a) Once the optimization algorithm clears a quantity of Capacity Resources with Actionable Subsidies that is equal to or greater than 5,000 megawatts of unforced capacity for the entire PJM Region in a Base Residual Auction for any Delivery Year, to

determine the Capacity Resource Clearing Prices for all Capacity Resources for such Delivery Year and all subsequent Delivery Years, as adjusted as necessary by any applicable Locational Price Adders, the Office of the Interconnection shall re-run the optimization algorithm using the same submitted Sell Offers, but for each Capacity Resource with Actionable Subsidy, the Office of the Interconnection shall apply an Actionable Subsidy Reference Price as determined in accordance with Tariff, Attachment DD, section 5.14(j)(4).

(b) If the initial optimization algorithm clears less than 5,000 megawatts of unforced capacity from Capacity Resources with Actionable Subsidies for the entire PJM Region, but the optimization algorithm clears a quantity of Capacity Resources with Actionable Subsidies that is equal to or greater than 3.5 percent of the Reliability Requirement for any modeled LDA, then, to determine the Capacity Resource Clearing Price for all Capacity Resources for such Delivery Year and all subsequent Delivery Years, as adjusted as necessary by any applicable Locational Price Adders, the Office of the Interconnection shall re-run the optimization algorithm using the same submitted Sell Offers, but for each Capacity Resource with an Actionable Subsidy in that modeled LDA, the Office of the Interconnection shall apply an Actionable Subsidy Reference Price as determined in accordance with Tariff, Attachment DD, section 5.14(j)(4).

(2) Capacity Resources with Actionable Subsidies.

A Capacity Resource that meets all of the following criteria shall be deemed to be a Capacity Resource with Actionable Subsidy:

(a) The Capacity Market Seller formally or informally, directly or indirectly, seeks, recovers, accepts or receives a Material Subsidy with regard to such Capacity Resource;

(b) The Capacity Resource is a Demand Resource or a Generation Capacity Resource or uprate, or planned uprate, to a Generation Capacity Resource that has an Unforced Capacity of 20 MW or greater;

(c) The Capacity Market Seller is a (i) Municipal/Cooperative Entity, which means cooperative and municipal utilities including public power supply entities comprised of either or both of the same, and joint action agencies, or a (ii) Vertically Integrated Utility, which 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) The Material Subsidy the Capacity Market Seller in any way receives for such Capacity Resource is greater than 1% of such Capacity Resource's actual or reasonably anticipated total revenues from markets administered by the Office of the Interconnection; and

(e) The Capacity Resource is a Generation Capacity Resource for which electricity production is not the primary purpose of the facility at which the energy is produced, but rather it is a byproduct of the resource's primary purpose.

(3) Process for Establishing a Capacity Resource with Actionable Subsidy.

(a) By no later than one hundred twenty (120) days prior to the commencement of the offer period of any Base Residual Auction, each Capacity Market Seller must provide for each Demand Resource, Generation Capacity Resource, and uprate, or planned uprate, of a Generation Capacity Resource that the seller intends to offer into the Base Residual Auction, information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. 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 whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the Base Residual Auction to update the Office of the Interconnection and the Market Monitoring Unit regarding any material changes in the qualifications of the Capacity Resource. The Office of Interconnection and the Market Monitoring Unit may request additional information from the Capacity Market Seller prior to the commencement of the offer period for the Base Residual Auction. Such Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) Business Days upon receipt of the request for additional information.

(b) For each Capacity Resource, an officer of the Capacity Market Seller must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy in accordance with section 5.14(j)(2), and if not, the officer must certify as to which criteria does not apply to the Capacity Resource.

(c) Once a Capacity Resource is a Capacity Resource with Actionable Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status pursuant to section 5.14(j)(5), or by Commission order. All Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status.

(4) Determination of Actionable Subsidy Reference Price.

For purposes of any re-run of the optimization algorithm pursuant to section 5.14(j)(1), the Actionable Subsidy Reference Price for each Capacity Resource with Actionable Subsidy shall be determined in accordance with the procedures below, depending on whether the Capacity Resource with Actionable Subsidy is an Existing Generation Capacity Resource, a Planned Generation Capacity Resource, or a Demand Resource.

(a) Prior to each Base Residual Auction for which a Capacity Market Seller intends to submit a Sell Offer based on an Existing Generation Capacity Resource that is deemed to be a Capacity Resource with Actionable Subsidy, the Office of the Interconnection shall determine an offer price, solely for the purposes of determining an Actionable Subsidy Reference Price under one of the following methods, as applicable:

(i) equal to the higher of:

(A) the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio, the number of Performance Assessment Hours, the Balancing Ratio, and the Capacity Performance bonus payment rate based on the actual market conditions and the actual circumstances of the unit; and

(B) (1) the Avoidable Cost Rate for such resource, without consideration of any Material Subsidy, determined, based on information provided by the Capacity Market Seller in accordance with the procedures and standards of Tariff, Attachment DD, sections 6.4, 6.7, and 6.8, that includes a risk premium for assuming a Capacity Performance obligation and that is net of Projected PJM Market Revenues, or (2) in lieu of using the resource-specific Avoidable Cost Rate calculated in accordance with the procedures and standards of Tariff, Attachment DD, sections 6.4, 6.7, and 6.8, the Capacity Market Seller may elect to use a default Avoidable Cost Rate that is net of Projected PJM Market Revenues. The Office of the Interconnection shall determine and post the default Avoidable Cost Rates for all resource types listed in Tariff, Attachment DD, section 6.7(c)(ii) as well as for nuclear, wind, and solar resources on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. For each Base Residual Auction, the Office of the Interconnection shall use the values stated in Tariff, Attachment DD, section 6.7(c)(ii) and adjust them based on the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission ("Handy-Whitman Index") to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The default Avoidable Cost Rates shall be expressed in dollar values for the applicable Delivery Year.

(ii) To the extent the methods expressed in Tariff, Attachment DD, sections 5.14(j)(4)(a)(i) is not applicable, the Actionable Subsidy Reference Price shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resources, as defined in Tariff, Attachment DD, section 6.4(a).

(b) Prior to each Base Residual Auction for which a Capacity Market Seller intends to submit a Sell Offer based on a Planned Generation Capacity Resource that is deemed to be a Capacity Resource with Actionable Subsidy, the Office of the Interconnection shall determine an offer price, solely for the purposes of determining an Actionable Subsidy Reference Price.

(i) The offer price shall be equal to the higher of (A) the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio, the number of Performance Assessment Hours, the

Balancing Ratio, and the Capacity Performance bonus payment rate based on the actual market conditions and the actual circumstances of the unit, or (B) the unit-specific offer price for such resource, which includes a risk premium for assuming a Capacity Performance obligation and is net of Projected PJM Market Revenues, that is determined, without consideration of any Material Subsidy, based on information provided by the Capacity Market Seller, and in accordance with the following procedures and standards:

(A) By no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, the Capacity Market Seller shall request a determination of a unit-specific offer price that 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, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals.

(B) The Capacity Market Seller must include in its request: documentation to support the fixed development, construction, operation, and maintenance costs of the Planned Generation Capacity Resource, as well as estimates of offsetting net revenues from PJM-administered markets. The financial modeling assumptions for calculating Cost of New Entry shall be the same modeling assumptions used to determine Cost of New Entry for the RPM auction parameters: (i) nominal levelization of gross costs, (ii) asset life of 20 years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. 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 proposed Actionable Subsidy Reference Price. 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 an exception hereunder. The request also shall identify all revenue sources relied upon in the proposed Actionable Subsidy Reference Price 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. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably sought by the Office of the Interconnection or the Market Monitoring Unit to evaluate the request. 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.

(C) The Market Monitoring Unit shall review the information and documentation in support of the submission and shall determine whether the requested unit-specific offer price is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than forty-five (45) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all proposed Actionable Subsidy Reference Price submissions and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination of whether the proposed Actionable Subsidy Reference Price is acceptable. If the Office of the Interconnection determines that the proposed Actionable Subsidy Reference Price is not acceptable, it shall calculate and provide to such Capacity Market Seller, a corrected Actionable Subsidy Reference Price based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the proposed Actionable Subsidy Reference Price is acceptable, the Office of the Interconnection shall notify the Market Monitoring Unit and the Capacity Market Seller, in writing, of the proposed Actionable Subsidy Reference Price by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.

(ii) To the extent the required information is not applicable and the Office of the Interconnection is unable to determine a unit-specific offer price, the Actionable Subsidy Reference Price shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resources, as defined in Tariff, Attachment DD, section 6.4(a).

(c) For Demand Resources the Actionable Subsidy Reference Prices shall be set at the same level as the default Market Seller Offer Cap for a Capacity Performance Resource as defined in Tariff, Attachment DD section 6.4(a).

(5) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy.

In the event the Office of the Interconnection reasonably believes that a certification of a Capacity Resource's status contains or is based on fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource (i) does not qualify as a

Capacity Resource with Actionable Subsidy and would not be subject to repricing or (ii) qualifies as a Capacity Resource with Actionable Subsidy and would be subject to repricing, then:

(a) the Office of the Interconnection will provide written notice of suspected fraudulent or material misrepresentation or omission to the Capacity Market Seller no later than sixty (60) days prior to the commencement of the offer period for the Base Residual Auction for which the seller submitted the certification. In such event, a resource that (i) does not qualify as a Capacity Resource with Actionable Subsidy will not be repriced in any re-run of the optimization algorithm conducted in accordance with section 5.14(j)(1) or (ii) qualifies as a Capacity Resource with Actionable Subsidy will be repriced in the re-run of the optimization algorithm conducted in accordance with section 5.14(j)(1). If the Office of the Interconnection, with advice and input from the Market Monitoring Unit, determines that a resource is subject to repricing as a Capacity Resource with Actionable Subsidy, the Office of Interconnection and Market Monitoring Unit may request any relevant documentation to determine the Actionable Subsidy Reference Price in accordance with this section 5.14(j)(5). In such case, the Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) Business Days upon receipt of the request for additional information. The Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary. A Capacity Market Seller may challenge the Office of Interconnection's determination of suspected fraudulent or material misrepresentation or omission by filing a petition with FERC;

(b) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least thirty (30) days before the start of the relevant Base Residual Auction, then the Office of the Interconnection may file the certification that contains any fraudulent or material misrepresentation or omission with FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(c) prior to applying the applicable offer price or Actionable Subsidy Reference Price in any re-run of the optimization algorithm pursuant to section 5.14(j)(1), the Office of the Interconnection, with advice and input of 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 fraudulent or material 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 submit a revised certification for that Capacity Resource for subsequent Base Residual Auctions, including Base Residual 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 fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection 5.14(j)(5) to be requested in any filing to FERC shall not be exclusive of any other actions, remedies, or penalties that may be pursued against the Capacity Market Seller by, including but not limited to, the Office of the Interconnection, the MMU, or others.

5.14A [Reserved.]**5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017**

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an “Affected Resource” and an “Affected Resource Owner,” respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource’s installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource’s Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction’s impact on the Affected Resource’s existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction’s impact on the Affected Resource’s existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource’s capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource’s total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B (“Transition Mechanism”).

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced

Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with

regard to the following information by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
 - ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.
1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.
 2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.
 3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in

the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource’s RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer

sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the

Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
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Record Narrative Name: OATT ATTACHMENT DD.5.14 Clearing Prices and Charges
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5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource

Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

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. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years

if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORD).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).
- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or
- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced

Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and
- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the

Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. 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 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. 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 based on a Capacity Resource with Actionable Subsidy submitted in any RPM Auction shall have an offer price no lower than the MOPR Floor Offer Price, unless the Capacity Market Seller has obtained a Unit-Specific Exception with respect to such Capacity Resource with Actionable Subsidy in such auction prior to the submission of such offer in accordance with the provisions of this subsection 5.14(h).

(2) Capacity Resource with Actionable Subsidy. A Capacity Resource that meets the following criteria shall be deemed to be a Capacity Resource with Actionable Subsidy:

(a) The Capacity Resource is a Generation Capacity Resource;

(b) The Capacity Market Seller formally or informally, directly or indirectly, seeks, recovers, accepts or receives a Material Subsidy with regard to such Capacity Resource;

(c) The Capacity Resource is not a 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; and

(d) The Capacity Market Seller has not obtained a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or an RPS Exemption for such

Capacity Resource, in accordance with the provisions of this subsection 5.14(h).

(3) Process for Establishing a Capacity Resource with Actionable Subsidy.

(a) By no later than one hundred twenty (120) days prior to the commencement of the offer period of any RPM Auction each Capacity Market Seller must provide for each Generation Capacity Resource, and uprate, or planned uprate, of a Generation Capacity Resource that the seller intends to offer into the RPM Auction, information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. 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 whether such Capacity Resource is a Capacity Resource with Actionable Subsidy. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the Office of the Interconnection and the Market Monitoring Unit regarding any material changes in the qualifications of the Capacity Resource. The Office of Interconnection and the Market Monitoring Unit may request additional information from the Capacity Market Seller prior to the commencement of the offer period for the RPM Auction. Such Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market Monitoring Unit within five (5) business days upon receipt of the request for additional information.

(b) For each Capacity Resource, an officer of the Capacity Market Seller must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy in accordance with Tariff, Attachment DD, section 5.14(h)(2), and if not, the officer must certify as to which criteria does not apply to the Capacity Resource. The officer must also indicate which, if any, of the exemptions set forth in Tariff, Attachment DD, sections 5.14(h)(7), (8), (9), or (10) apply to the Capacity Resource.

(c) Once a Capacity Resource is a Capacity Resource with Actionable Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status pursuant to Tariff, Attachment DD, section 5.14(h)(12), or by Commission order. All Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status.

(4) MOPR Floor Offer Price. The MOPR Floor Offer Price for a Capacity Resource with Actionable Subsidy shall be the product of the Net Cost of New Entry (applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered) times the average of the Balancing Ratios during the Performance Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year.

(5) Effect of Exemption or Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a Capacity Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, any of the exemptions defined in Tariff,

Attachment DD, sections 5.14(h)(7), (8), (9), or (10), 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 Capacity Resource with Actionable Subsidy 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.

(6) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer for a Capacity Resource with Actionable Subsidy in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year may, at its election, submit a request for a Unit-Specific Exception for such Capacity Resource with Actionable Subsidy. Such a request may be in addition to, or in lieu of, a determination that such Capacity Resource is exempt from being a Capacity Resource with Actionable Subsidy via the Self-Supply Exemption, the Competitive Exemption, the Public Entity Exemption, or the RPS Exemption. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-priced 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:

(a) 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 Tariff, Attachment DD, section (h)(11)(a) 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.

(b) For a Unit-Specific Exception for Generation Capacity Resources for which a Sell Offer based on such resource has not cleared in an RPM Auction for any prior Delivery Year, 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 Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry shall be the same modeling assumptions used to determine Cost of New Entry for the RPM Auction parameters: (i) nominal levelization of gross costs, (ii) asset life of twenty (20) years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. 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. In addition to the certification, signed by an officer of the Capacity Market Seller, required by Tariff, Attachment DD, section 5.14(h)(11)(c), the request must include a certification 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.

(c) For a Unit-Specific Exception for Generation Capacity Resources for which a Sell Offer based on such resource has cleared in an RPM Auction for any prior Delivery Year, as more fully set forth in the PJM Manuals, a Capacity Market Seller using a Unit Specific Exception other than the Unit Specific Exception applicable to new entry in accordance with Tariff, Attachment DD, section 5.14(h)(6)(b), shall submit a Sell Offer equal to the higher of the Avoidable Cost Rate, as defined in Tariff, Attachment DD, section 6.8(a), net of Projected PJM Market Revenues, and the value obtained by incorporating the opportunity cost of Capacity Performance participation in a manner consistent with the derivation of the Market Seller Offer Cap, but employing alternative assumptions for the availability ratio (A), the number of Performance Assessment Hours (H), the Balancing Ratio (B), and the Capacity Performance bonus payment rate (CPBR) based on the actual market conditions and the actual circumstances of the unit. All supporting data must be provided for all requests.

(d) 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.

(7) **Self-Supply Exemption.** A Capacity Market Seller that is a Self-Supply LSE may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for a Self-Supply Exemption if such Capacity Resource satisfies the criteria specified below:

(a) **Cost and revenue criteria.** The costs and revenues associated with a Capacity 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 Capacity Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated Utility and the Capacity 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) 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 Capacity 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 Capacity Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the Capacity 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.

(b) **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 Capacity 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 Capacity Resource.

(c) **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 Capacity 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 |
| Vertically Integrated Utility | 20% of LSE's Reliability Requirement |

(d) **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 Capacity 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 only the RPM Auction in which such threshold is exceeded.

(e) 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 or existing 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.

(f) For purposes of the Self-Supply Exemption:

(i) “Self-Supply LSE” means the following types of Load Serving Entity, which operate under long-standing business models: Single Customer Entity or Vertically Integrated Utility.

(ii) “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.

(iii) “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.

(iv) All capacity calculations shall be on an Unforced Capacity basis.

(v) 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.

(vi) 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 Capacity Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a Capacity Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(vii) "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 Exemption. To qualify for a Self-Supply Entry exemption, the resource 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 the resource is for the Self-Supply LSE's use to supply its customer(s).

(viii) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the Capacity 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.

(8) Competitive Exemption. A Capacity Market Seller may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for such resource if the Capacity Market Seller demonstrates that such Capacity Resource satisfies all of the following criteria:

(a) No costs of the Capacity Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Tariff, Attachment DD, sections 5.14(h)(8)(b) and (c), to the extent either or both are applicable to such resource, are satisfied.

(b) No costs of the Capacity 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.

(c) The Capacity Market Seller does not receive a Material Subsidy.

(9) Public Entity Exemption. A Capacity Market Seller that is an Electric Cooperative or a Public Power Entity, as defined in Article 1 of the Reliability Assurance Agreement, may qualify a Capacity Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for a Public Entity Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that such Capacity Resource satisfies all of the following criteria:

(a) The long-term resource plans for a public entity’s Owned and Contracted Capacity, as defined in Tariff, Attachment DD, section 5.14(h)(7), are consistent with its business model and such resource plans are intended to be balanced with its load obligations (i.e., over such long-term planning horizon, the entity’s resources are planned to be less than or equal to its LSE Total Estimated Capacity Obligation) (The public entity shall notify the Office of the Interconnection and the Market Monitoring Unit when it expects its Owned and Contracted Capacity to be greater than its LSE Total Estimated Capacity Obligation in the next RPM Delivery Year and describe the consistency of the investment decision with its business model);

(b) The Electric Cooperative’s or Public Power Entity’s Owned and Contracted Capacity is less than or equal to 600 MW greater than LSE Total Estimated Capacity Obligation in any Delivery Year;

(c) The criteria concerning cost and revenue set forth in Tariff, Attachment DD, section 5.14(h)(7)(a) are satisfied.

Any excess supply, starting with the Capacity Resource(s) most recently added to the portfolio, will be subject to the Minimum Offer Price Rule unless the Capacity Resource qualifies for a Unit-Specific Exception under Tariff, Attachment DD, section 5.14(h)(6), where excess supply is the MW amount of Owned and Contracted Capacity in excess of the sum of LSE Total Estimated Capacity Obligation and 600 MW. The Minimum Offer Price Rule or Unit-Specific Exception shall apply to the last unit(s) added to Owned and Contracted Capacity.

(10) RPS Exemption. A Capacity Market Seller may qualify a Capacity

Resource with Actionable Subsidy, as defined in Tariff, Attachment DD, section 5.14(h)(2), in any RPM Auction for any Delivery Year for an RPS Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that such Capacity Resource satisfies either:

(a) the following criterion: the Capacity Resource was procured in a program in compliance with a state-mandated renewable portfolio standard prior to December 31, 2018, or based on a request for proposals (RFP) issued under such program prior to December 31, 2018; or

(b) the following criteria:

(i) the Capacity Resource complies with the requirements of a state-mandated renewable portfolio standard or voluntary renewable portfolio standard;

(ii) the terms of such program are competitive and non-discriminatory, meaning that (1) the program requires LSEs to procure a defined amount of renewable Capacity Resources, (2) both new and existing Capacity Resources may participate, (3) all supplies of renewable Capacity Resources may participate, (4) the requirements of the program are fully objective and transparent, (5) the program terms do not include selection criteria that could give preference to new or existing resources, (6) the program terms do not use indirect means to discriminate against new or existing Capacity Resources, (7) the program terms do not use any locational requirement, e.g., offshore wind, other than restricting imports from other states, and (8) the renewable characteristic is the only screen for participation in the program where renewable does not include coal, natural gas, or nuclear thermal resources;

(iii) if the program does not use an auction, the terms of such program: (1) are consistent with fair market value and standard industry practice and (2) provide that the price paid for renewable energy credits is determined by the contract terms between the buyer and the seller;

(iv) if the program uses an auction either as either a means of procuring renewable attributes to meet state requirements, or as a means to facilitate the procurement of renewable attributes by responsible LSEs, such auction must be competitive and non-discriminatory, meaning (1) winner(s) of auction based on lowest offer prices, (2) payments to winners based on auction clearing price, and (3) at least three non-affiliated sellers participate.

(11) Exemption/Exception Process.

(a) 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.

(b) The Capacity Market Seller must submit its request for a Unit-Specific Exception, or an exemption defined in Tariff, Attachment DD, sections 5.14(h)(7), (8), (9), or (10) 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 Capacity 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 5.14(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.

(c) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has (A) 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 Capacity Resource and seek for such resource either a (1) Unit-Specific Exception from the MOPR Floor Offer Price or (2) a Self-Supply Exemption, a Competitive Exemption, a Public Entity Exemption, or an RPS Exemption from being a Capacity Resource with Actionable Subsidy, and (B), to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception or exemption is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception or exemption; and (3) the request satisfies the criteria for the exception or exemption.

(d) 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.

(12) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy.

In the event the Office of the Interconnection reasonably believes that a certification of a Capacity Resource's status contains or is based on fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource is a Capacity Resource with Actionable Subsidy or does not qualify for a Unit-Specific Exception, then:

(a) the Office of the Interconnection will provide written notice of suspected fraudulent or material misrepresentation or omission 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 the certification. In such event, a resource that is a Capacity Resource with Actionable Subsidy shall be subject to the Minimum Offer Price Rule. The Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary. A Capacity Market Seller may challenge the Office of Interconnection's determination of suspected fraudulent or material misrepresentation or omission by filing a petition with FERC;

(b) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least thirty (30) days before the start of the relevant RPM Auction, then the Office of the Interconnection may file the certification that contains any alleged fraudulent or material misrepresentation or omission with FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(c) prior to applying the Minimum Offer Price Rule, the Office of the Interconnection, with advice and input of 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 fraudulent or material 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 submit a revised certification for that Capacity Resource for subsequent RPM Auctions, including RPM 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 fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection 5.14(h)(12) to be requested in any filing to FERC shall not be exclusive of any other actions, remedies, or penalties that may be pursued against the Capacity Market Seller by, including but not limited to, the Office of the Interconnection, the MMU, or others.

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 [Reserved.]

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an “Affected Resource” and an “Affected Resource Owner,” respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource’s installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource’s Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction’s impact on the Affected Resource’s existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction’s impact on the Affected Resource’s existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource’s capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource’s total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B (“Transition Mechanism”).

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the

RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell

megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that

utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an

external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited

DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource

and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

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