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October 29, 2018

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

Re: *PJM Interconnection, L.L.C.*, Docket No. ER19-210-000
Maintenance Adder Revisions to the PJM Open Access Transmission Tariff

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to sections 205 and 206 of the Federal Power Act ("FPA"), 16 U.S.C. §§ 824d and 824e, hereby submits revisions to the PJM Open Access Transmission Tariff ("Tariff"), Attachment DD, section 6.8(c) and the Amended and Restated Operating Agreement of PJM ("Operating Agreement"), Schedule 2[1] to eliminate a current restriction that unreasonably prevents sellers of energy from combined cycle ("CC") and combustion turbine ("CT") plants from including in their energy market offers the same type of plant maintenance costs that sellers from all other resource types are permitted to include.

As shown in this filing, there is no justification for this disparate treatment, which unfairly disadvantages sellers of energy from CC and CT plants by raising a risk of under-recovery of costs that all other sellers are permitted to include in their cost-based

[1] Consistent with the Commission's eTariff rules, PJM is filing the proposed revisions to the Operating Agreement in a new EL19 docket under section 206, and the proposed revisions to the Tariff in a new ER19 docket under section 205. *See, e.g.*, *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,091, at P 1 n.4 (2014). PJM is filing this transmittal in substantially the same form in both dockets.

offers in the energy market. That unsustainable difference in treatment is unduly discriminatory and thus unlawful under the FPA. While the restriction on CC and CT plants is stated in the PJM manual that implements and defines Operating Agreement, Schedule 2, this differing treatment can be most authoritatively resolved through changes to Schedule 2 itself and a related Tariff provision.[2] PJM therefore respectfully requests that the Commission find that the current rules are unduly discriminatory, and require a remedy. To that end, PJM requests that the Commission accept, as just and reasonable, the replacement rules described in this filing. PJM's proposed revisions will clarify that:

- Sellers of energy from CC plants and CT plants may include in their cost-based energy market offers a major maintenance cost component (major inspection and overhaul costs) in the same manner, and under the same conditions, as sellers of energy from other plants may include comparable costs in their energy offers;

- Most importantly, such maintenance expenses may be included only if the expenses are incurred as a result of electric production, meaning (in the case of CC and CT plants) that the maintenance is directly related to the number of unit starts or run hours;

- Consistent with this principle, and with current rules, plant operators employing long-term service agreements for maintenance[3] may include in

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[2] Because the current restriction on CC and CT plant energy market offers was effected through a PJM Manual change in 2012, it was not presented to the Commission for decision, and the Commission has not had a prior occasion to address it. As explained below, that manual change was based on an understanding that nuclear and fossil-steam plants do not include these maintenance costs in their energy market offers. That understanding was incorrect, as revealed in 2017 upon review of maintenance expense history information provided to PJM beginning that year as a result of changes to Operating Agreement, Schedule 2.

[3] As used here, long-term service agreements ("LTSAs") refer to contracts with third parties that provide maintenance, inspection, and overhaul services on generation equipment.

cost-based energy offers only the portion of costs under such LTSAs for activities directly related to the number of unit starts and run hours. Fixed payments to the contractor (in the nature of retainer charges or stand-by charges) may not be included; and

- To the extent that a seller intends to include a major maintenance expense component in its energy market offer in a given Delivery Year, it may not also include those same major maintenance expenses in its capacity market offer for the same Delivery Year.

PJM's proposal is in accord with the Commission's approval earlier this month for another regional market operator of "a major maintenance cost component for mitigated start-up offers and mitigated no-load offers."[4] The key difference here is that PJM *already has* such a component in its market rules, but it is expressly not available to CC and CT plants. PJM submits this filing so that the Commission can correct that unreasonable difference, and make clear that the permissible major maintenance costs, as in *SPP*, are those "associated with the number of unit starts and run hours" for the resource.[5]

PJM notes a relationship between this filing and PJM's October 12, 2018 filing in Docket No. ER19-105-000 of Tariff changes on the demand curve parameters of PJM's capacity auction, including the estimated cost of new entry ("CONE") by a representative combustion turbine plant.[6] In that filing, PJM excludes the cost of major inspection and overhaul costs from the CONE calculation, which reduces the gross CONE estimate in that case, and increases the Tariff's stated estimate for the Variable O&M costs of the

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4 *Sw. Power Pool, Inc.*, 165 FERC ¶ 61,026, at P 1 (2018) ("*SPP*").

5 *Id.* at P 2.

6 PJM notes that filing was amended on October 26, 2018, in Docket No. ER19-105-001, solely to revise the requested the effective date.

reference CT plant, which is used to calculate the Energy and Ancillary Services revenue estimate that offsets gross CONE. However, to address the possibility that the Commission does not grant the relief sought in this case, PJM also provided alternative estimates of CONE and Variable O&M in the ER19-105 filing that assume the major maintenance costs are recovered in the capacity market, rather than in the energy market.[7]

To be clear, the Variable Resource Requirement Curve proceeding in Docket No. ER19-105 is not dependent on this proceeding. The Commission can decide independently in that proceeding whether it is just and reasonable to include the referenced maintenance costs in CONE, and PJM provided alternative rate calculations in its initial filing in that docket to put all parties on notice of such rates and accommodate the Commission's decision on that issue. However, if the Commission acts on this proceeding before its final order in the Docket No. ER19-105 proceeding, its decision here can inform its action there. In any event, PJM urges the Commission to issue its final order on this filing by March 31, 2019. A final order by that date would allow PJM sufficient time, if necessary, to submit an appropriate filing to ensure consistency between the energy market rules ordered here and the capacity market parameters that must be posted by no later than May 1, 2019, for use in the August 2019 Base Residual Auction. PJM accordingly is requesting in its parallel section 206 filing being made

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7 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters of PJM Interconnection, L.L.C., Docket No. ER19-105-000, at 19-20 (Oct. 12, 2018) ("Quadrennial Filing").

today that the Commission set March 31, 2019, as the refund effective date required by section 206.[8]

I. THE CURRENT OPERATING AGREEMENT RULES UNREASONABLY BAR SELLERS WITH CC OR CT PLANTS FROM REFLECTING MAJOR MAINTENANCE EXPENSES IN THE MAINTENANCE ADDER OF THEIR COST-BASED ENERGY MARKET OFFERS

The existing Operating Agreement, as applied and further detailed through the PJM manuals, unduly discriminates against CT and CC plants.[9] Other types of generation facilities, including steam and nuclear plants, can reflect major maintenance expenses in the Maintenance Adder[10] component of their cost-based energy market offers; but CC and CT plants cannot include such costs. There is no reasonable basis for

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8 Consistent with the required eTariff convention when simultaneously filing interdependent section 205 and 206 changes, PJM has assigned the section 205 changes an indeterminate effective date of 12/31/9998, so as not to constrain the Commission's time for acting on the section 206 changes.

9 CT plants are designed to start quickly to meet peak power demands when needed. CT plants operate by drawing in compressed air, mixing it with a fuel source, and igniting the mixture to cause the gasses in the mixture to expand and move turbine blades connected to a generator to produce electricity. A CC plant typically uses a CT but adds one or more heat-recovery steam generators (i.e., boilers) to use the heat generated by a CT to heat water to produce steam that can move steam turbine blades connected to a generator to produce additional electricity. Adding steam boilers and turbines to a CT to make a CC plant increases the efficiency of energy production from the CT, but both CC and CT plants utilize the same core technology of a CT.

10 The Operating Agreement defines a Maintenance Adder as "an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy . . . and [that] may only include expenses incurred as a result of electric production." Operating Agreement § 1, Definitions M – N; Tariff § 1 Definitions L – M – N. As discussed below, the Maintenance Adder considers multi-year maintenance expense history, and derives an hourly equivalent charge to reflect those expenses.

this distinction. All of these plant types have maintenance costs that are incurred as a result of electric production. All should be permitted to include in their cost-based offers a component based on their major maintenance expenses, so long as those expenses are incurred as a result of electric production (e.g., are directly related to unit starts and run times). At present, however, a provision of PJM Manual 15 provides[11] that CCs and CTs—and only CCs and CTs—are expressly forbidden from including those costs in their energy offers. As explained in section I.C.3 below, PJM adopted this restriction (which as a PJM Manual change did not require Commission review or approval) based on an understanding that nuclear and fossil-steam plants did not include such maintenance costs in their energy market offers. That understanding was incorrect, as PJM found in 2017 once it began receiving additional maintenance adder information as a result of Operating Agreement Schedule 2 changes, Market Sellers with nuclear and fossil steam plants do base their energy offers on these maintenance expenses. It thus has become clear that sellers of CC and CT plants should be allowed to do so as well.

A. The Operating Agreement Allows Sellers of Energy from All Other Types of Generating Facilities Other Than CC and CT Plants to Include in Their Energy Market Offers a Component Based on Expenses Incurred Over a Long-term Historical (Ten-Year or Twenty-Year) Period to Maintain Their Boilers, Generators, and Associated Equipment, So Long as Those Expenses Are Incurred as a Result of Electric Production.

PJM Operating Agreement, Schedule 2, governs the costs that sellers may include in their energy market offers. "[A]ll generating units" are expressly permitted to include

[11] Cost Development Subcommittee, *PJM Manual 15: Cost Development Guidelines*, PJM Interconnection, L.L.C., §§ 5.6.1, 6.6.2 (May 15, 2017), https://www.pjm.com/-/media/documents/manuals/m15.ashx ("Manual 15").

"Maintenance Adders,"[12] which the Operating Agreement defines as "an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy . . . and [that] may only include expenses incurred as a result of electric production."[13] Schedule 2 provides that the PJM Board of Managers shall "define in detail the method of determining the costs entering into [such cost] components" and that sellers "shall adhere to such definitions."[14]

Those cost determination details are set forth in Manual 15, entitled "Cost Development Guidelines." Manual 15 states that, for all generation resource types, Variable Maintenance cost is "the parts and labor expense of maintaining facilities in satisfactory operating condition"[15] and that the Maintenance Adder (for all resource types) is based on "all available maintenance expense history" for a rolling historical period of ten or twenty years, at the seller's election.[16] Manual 15 provides instruction on the calculation of a unit specific maintenance adder, defined as total maintenance dollars divided by equivalent unit service hours, total generation, or total fuel, depending on the

12 Operating Agreement, Schedule 2 § 1.1.

13 Operating Agreement § 1, Definitions M – N; Tariff § 1, Definitions L – M – N. The Commission accepted this definition of the Maintenance Adder in 2017 over the objection of the Independent Market Monitor for the PJM Region, who argued that the underlying variable O&M costs were not short-run marginal costs that should be included in energy market offers. *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,133, at PP 122-25 (2017).

14 Operating Agreement, Schedule 2 § 1.2.

15 Manual 15 § 2.6.

16 *Id.*

unit type.[17] Manual 15 further specifies that "[o]nly expenses incurred as a result of electric production qualify for inclusion."[18]

Manual 15 prescribes additional maintenance adder rules for particular generation resource classes. Nuclear Maintenance Adders are intended to recover costs in Account Nos. 530 and 531 of the Commission's Uniform System of Accounts ("U.S. of A."),[19] which are defined to include "the cost of labor, materials used and expenses incurred in the maintenance of," respectively, the nuclear reactor and related equipment used to produce steam and the turbo-generators and related equipment that use that steam to generate electricity.[20]

Similarly, Manual 15 prescribes a Fossil Steam Maintenance Adder intended to recover costs in Account Nos. 512 and 513 of the U.S. of A.,[21] which are defined to include "the cost of labor, materials used and expenses incurred in the maintenance of," respectively, boilers and related equipment (including coal, oil, or gas fuel handling equipment) used to produce steam, and the engine-driven generators or turbo-generators and related equipment that use that steam to generate electricity.[22]

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17 *See* Manual 15 § 2.6.4.

18 *Id.* § 2.6.

19 *Id.* § 3.6.

20 18 C.F.R. part 101, Account Nos. 530 and 531 (referencing (respectively) Plant Account Nos. 322 and 323).

21 Manual 15 § 4.6.

22 18 C.F.R. part 101, Account Nos. 512 and 513 (referencing (respectively) Plant Account Nos. 312 and 313/314).

In sum, nuclear and fossil-steam plants may include in their cost-based energy offers an adder derived from expenses that are:

- incurred to maintain facilities in satisfactory operating condition;
- based on all available maintenance expense history over a ten-year or twenty-year period;
- incurred as a result of electric production; and
- for maintenance of boilers, generators (including turbo-generators) and associated equipment.

B. Unlike the Rules for Nuclear and Fossil-Steam Plants, the Current Rules for CC and CT Plants Expressly Exclude from Maintenance Adders Major Inspection and Overhaul Expenses.

The Maintenance Adder rules prescribed by the Operating Agreement and Manual 15 for CCs and CTs track, in form, the rules for nuclear and fossil-steam plants. The ten-year or twenty-year historical expense period rules, which apply to "all generating units," facially apply to CT and CC plants. Moreover, similar to the rules for nuclear and steam plants, Manual 15 prescribes a Combined Cycle Maintenance Adder[23] intended to recover costs in Account Nos. 512, 513, and 553 of the U.S. of A., and a CT Maintenance Adder intended to recover costs in Account No. 553. Account Nos. 512 and 513, as noted above, include the costs of labor, materials and expenses for maintenance of boilers, generators, and related equipment. Account No. 553 includes such expenses for maintenance of prime movers and power-driven main generators, and their associated equipment.[24]

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[23] Manual 15 § 5.6.

[24] 18 C.F.R. part 101, Account No. 553 (referencing Plant Account Nos. 343 and 344).

Manual 15 also allows CT and CC Maintenance Adders to include (subject to PJM consent) variable long-term maintenance costs under LTSAs (for a third party to perform overhaul and maintenance work) so long as (i) the variable long-term maintenance costs "are consistent with the definition of such costs in the Cost Development Guidelines" (i.e., Manual 15) and (ii) the agreement specifically sets the dollar value of each component of the variable long-term maintenance costs.[25]

However, the current version of Manual 15 contains provisions that rescind, for CC and CT plants, much of the Maintenance Adder authority that Schedule 2 and Manual 15 otherwise seemingly grant. Specifically, Manual 15 provides that "CC Plant major inspection and overhaul expenses" and "CT Plant major inspection and overhaul expenses" may only be included in variable maintenance expenses until June 1, 2015.[26] As explained by Thomas M. Hauske, a Senior Lead Engineer in Operations Analysis & Compliance for PJM, in his accompanying affidavit ("Hauske Aff."), this denies CC and CT plants the opportunity to reflect in their energy offers a majority of the costs that would otherwise be considered variable O&M.[27]

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[25] Manual 15 §§ 5.6.1 (CCs) & 6.6.2 (CTs).

[26] Manual 15 §§ 5.6.2 (CCs) & 6.6 (CTs). Specifically, any such expenses, even if previously approved, must have been removed from the ten- or twenty-year maintenance history for Maintenance Adders used on or after June 1, 2015.

[27] *See* Hauske Aff. ¶ 15.

C. There Is No Justification for this Disparate Treatment.

1. CC/CT Major Inspection and Overhaul Expenses Are Not Categorically Different from Major Maintenance Expenses that Nuclear and Fossil-Steam Plants Are Permitted to Include, and in Fact Include, in Their Energy Market Offers.

The expenses at issue are similar, whether incurred by CC and CT plants, or by other types of plants. On their face, Schedule 2 and Manual 15 permit nuclear and fossil-steam plants to include such maintenance costs, whether or not they might be characterized as "major." Indeed, ten or twenty years of "all available maintenance expense history," as allowed by Manual 15, section 2.6, will necessarily capture one or more instances of "major" maintenance at nuclear or steam plants that is required "to maintain facilities in satisfactory operating condition." So long as maintenance expenses are incurred as a result of electric production, they should be included in Maintenance Adders for CC and CT plants, just as they are for nuclear and steam plants.

As Mr. Hauske explains, there is nothing intrinsic in combustion turbine generating equipment that makes its required maintenance activities uniquely "major" compared to the activities needed to maintain nuclear or fossil boiler or generation plant in satisfactory operating condition. In each case, major maintenance of a CT generator and major maintenance of the steam turbine generator of a nuclear or fossil boiler requires removal of the casing, and repair and replacement of blades, diaphragms, and other turbine components. In each case, major maintenance is typically performed only when the turbine, whether CT or steam turbine, is near or has exceeded an Original Equipment Manufacturer's ("OEMs") recommended operating interval based on either starts or operating hours.

Moreover, nuclear and fossil-steam plants do in fact include major maintenance expenses in their cost-based energy offers. PJM conducted a review of unit-specific Maintenance Adders in 2017, which included units with both ten- and twenty-year maintenance cost histories, and confirmed that such costs have been included by both nuclear and fossil-steam plants. PJM's 2017 review showed that nuclear and fossil-steam plants included major maintenance expenses in their energy market offers both before and after PJM revised Manual 15 to deny CC and CT plants the option to include such expenses in their energy market offers.[28] PJM estimates that up to fifty-three nuclear and fossil-steam units included major maintenance in their maintenance history.[29] Thus: (i) Schedule 2 and Manual 15 permit nuclear and steam plants to include major maintenance costs in their energy offers; and (ii) those plants in fact have included such costs in their energy offers.

2. CT and CC Major Maintenance Expenses Are Incurred as a Result of Electric Production.

The key criterion in Manual 15 for identifying variable expenses includible in the calculation of a Maintenance Adder is that they are incurred as a result of electric production. Major inspection and overhaul expenses for CT and CC plants will often meet this test. Simply put, the timing of *when* a combustion turbine unit must undergo major inspection is primarily determined by *how often* and *how long* the unit runs for electric production. As recognized in *SPP*, "the operation of a resource results in gradual

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[28] Hauske Aff. ¶ 8.

[29] *Id.*

deterioration of equipment and therefore requires maintenance to sustain the resource's ability to operate."[30] Consequently, "major maintenance costs will be a variable cost component of the mitigated offer and will be directly related to both the decision to start a resource and/or the number of hours the resource is operated."[31]

The primary source of standards on combustion turbine inspection and maintenance is the combustion turbine manufacturer; indeed, warranty coverage may depend on close compliance with the manufacturer's maintenance standards. For example, General Electric, the manufacturer of many combustion turbines recently added to the PJM Region,[32] advises in its guidance document which "for over 28 years . . . has long stood . . . as the standard for O&M tradeoffs for GE Gas Turbines,"[33] that "GE bases most gas turbine maintenance requirements on independent counts of starts and hours. Whichever criteria limit is first reached determines the maintenance interval."[34] The guide evidences sensitivity to maintenance cost control and encourages use of

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30 *SPP* at P 16.

31 *Id.*

32 Hauske Aff. ¶ 9 (citing 2018 CONE Study at 15, Table 6 (GE turbines account for 38% of the total CC capacity installed or under construction in the PJM Region since 2014).

33 Justin Eggart, Christopher E. Thompson, Jerry Sasser, Mardy Merrie, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*, GE Power, Foreward (Oct. 2017), https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/technical/ger/ger-3620n-heavy-duty-gas-turbine-operationg-maintenance-considerations.pdf.

34 *Id.* at 5.

sophisticated data monitoring and analytics to help determine maintenance patterns.[35] General Electric's 2009 version of the same guidance document similarly noted that even then, General Electric based its gas turbine maintenance requirements on unit-specific counts of starts and run hours.[36] In the same vein, Siemens, the manufacturer of turbine models accounting for approximately one third of PJM Region CC capacity, recognizes the variability of major maintenance intervals and offers turbine purchasers generator equipment upgrades that Siemens claims will extend intervals for major inspections from a typical 50,000 "equivalent baseload hours" or 1,800 "equivalent starts" to 66,000 equivalent baseload hours or 2,400 equivalent starts.[37]

Mr. Hauske, whose thirty-six-year engineering career has included support for maintenance of nuclear, steam, CC, and CT plants,[38] reinforces this point in his accompanying affidavit, explaining that major inspection and overhaul timing can vary significantly depending on how often the plant is called upon and for how long the plant operates each time it is called upon.[39] These maintenance intervals are directly tied to

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35 *See id.* at 3, 22, 30, 36.

36 David Balevic, Steven Hartman, Ross Youmans, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*, GE Power, 5 (Nov. 2009), https://www.scribd.com/document/41225485/GER3620L-Nov-3-09b-rev.

37 *Internal Extension – Combustion System Upgrades*, Siemens https://www.siemens.com/global/en/home/products/energy/services/performance-enhancement/modernization-upgrades/gas-turbines/interval-extension-combustion-system-upgrade-sgt-5000f.html (last visited Oct. 26, 2018).

38 Hauske Aff. ¶¶ 2, 3.

39 *Id.* ¶ 10.

electric production and can be difficult to predict with changing market conditions.[40] They are not a fixed cost incurred at every defined number of years regardless of operation of the unit.[41] They are variable and become necessary when the unit is either near or has exceeded the OEM's recommendations.[42]

If a CC or CT plant experiences long periods with comparatively few hours of electric production, such as when it is used for peaking operation, the first major inspection and overhaul could be years later than any calendar-based interval the OEM offers as a reference.[43] Conversely, if a CC or CT plant experiences periods of frequent electric production, such as in baseload operation or by cycling frequently, major inspection and overhaul could be needed sooner.[44]

The fundamental consideration, therefore, is not unlike maintenance for the brakes on your car. Brakes are typically designed to operate for a range of driving mileage, such as 30,000 to 40,000 miles.[45] However, if an automobile performs long periods of mostly highway driving, the same brakes could last until 50,000 miles.[46] In contrast, if the same automobile experiences frequent quick starts and stops due to urban

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40 *Id.*

41 *Id.*

42 *Id.*

43 *Id.* ¶ 11.

44 *Id.*

45 *Id.* ¶ 12.

46 *Id.*

driving, the same brakes may only last to 15,000 miles.[47] Replacement of the brakes is a variable major maintenance expense directly tied to the operation of the vehicle, comparable to a CT unit's major maintenance that is directly tied to its electric production.[48] Operators of CC plants or CT plants are unfairly disadvantaged by being prevented, unlike other plant operators, from including these maintenance costs in energy market offers. It is difficult to estimate these costs accurately for a capacity offer three years in advance of a Delivery Year, precisely because it is hard to predict how often and for how long the plant will be operated during that future year. CC and CT plants' major maintenance costs are more reliably determined as part of offers into the energy market, which has a much shorter time horizon between bids and performance.

In short, as in *SPP*, "includ[ing] a major maintenance component in mitigated . . . offers . . . [is] a just and reasonable means of addressing concerns over the recovery of costs resulting from the gradual deterioration of resources operating equipment in the [energy market]."[49]

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47 *Id.*

48 *Id.* Underscoring that such costs are variable, the Commission accepted PJM's proposal to include in energy market offers a Maintenance Adder that "may only include expenses incurred as a result of electric production," over objections of the IMM that the underlying maintenance costs are "fixed." *See PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,133, at PP 122 n.170, 123 n.173, 125.

49 *SPP* at P 16.

3. Nothing in the 2012 Manual Change that Added this Restriction on CC and CT Major Maintenance Expenses Justifies Retaining this Unduly Discriminatory Restriction.

PJM amended Manual 15 in early 2012 to implement the restriction at issue here, i.e., preventing CC plants and CT plants from including major inspection and overhaul expenses in calculating their Maintenance Adders. That fact does not justify retaining this restriction, which as plainly set forth above unduly discriminates against CC and CT plants. As explained by Mr. Hauske, PJM's understanding in 2011 and 2012 was that all other resource types included their comparable inspection and overhaul expenses in determining their capacity market offers, rather than in determining their energy market offers.[50] Because other Manual 15 provisions make clear that maintenance costs included in energy offers cannot be included in capacity offers, PJM thought the change was necessary at that time to put CC plants and CT plants in the same position perceived for all other resource types—reflecting these costs in their capacity offers, but not their energy offers.[51]

However, PJM's factual premise was incorrect: Other resource types *do include* comparable major maintenance expenses in their energy offers. PJM did not have regular access at that time to the offer component data needed to verify the contrary assumption that prompted the 2012 change. PJM only gained access to energy market offer component data in 2017 after proposing revisions to Operating Agreement, Schedule 2, section 4.1, to become effective May 15, 2017, to annually collect such information from

[50] Hauske Aff. ¶ 14.

[51] *Id.*

Market Sellers.[52] Based on PJM's review of recently provided offer component data, it is now clear to PJM that energy market offers from other resources include major maintenance costs. Consequently, the 2012 amendment to Manual 15, which had the laudable objective of putting CC plants and CT plants on the same basis as all other resource types with respect to their capacity offers, instead had the unintended effect of saddling CC plants and CT plants with a unique *in*ability to reflect such expenses in their energy offers.

D. As Required by the FPA, the Commission Must Act to Eliminate this Undue Discrimination.

As demonstrated above, PJM's current Tariff and Operating Agreement unduly discriminate against CC and CT plants. The Commission must take action to remedy this discriminatory treatment. The Commission has long acknowledged that it is bound to act when it is confronted with undue discrimination in wholesale energy markets.[53] Above all, the Commission's obligation under both sections 205 and 206 of the FPA is to

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[52] *See* Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER16-372-003, at 8–10, 19–20 (Mar. 6, 2017).

[53] *See, e.g., 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 31,635 (1996) ("Indeed, it is our statutory obligation under sections 205 and 206 of the Federal Power Act (FPA) to remedy undue discrimination."); *Mid-Continent Area Power Pool*, Opinion No. 806, 58 FPC 2622, at 2636 (1977) ("[T]hat fact does not mollify the discrimination inherent in Article IV which we must, under Sections 205 and 206 of the Federal Power Act, remedy.").

eradicate undue discrimination by public utilities.[54] In the absence of action to remedy the discriminatory treatment of CC and CT plants, the Commission would be condoning discrimination in violation of the FPA.

II. THE PROPOSED OPERATING AGREEMENT AND TARIFF REVISIONS ARE JUST AND REASONABLE.[55]

During the extensive stakeholder process to address this issue, PJM initially proposed changing only Manual 15. Stakeholders suggested, however, and PJM agreed, that this issue was best resolved through changes to the Operating Agreement and Tariff, as well as through conforming changes to Manual 15. The Markets and Reliability Committee endorsed the proposed changes at its September 27, 2018 meeting, with a sector vote of 3.40 out of 5.0 in favor. The proposal failed, however, before the Members Committee that same day, with a sector vote of 2.92 out of 5.0 in favor. Because

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54 *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, 2001–2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,160, at P 698 (2004) ("Sections 205 and 206 of the FPA require the Commission to address and remedy undue discrimination by public utilities."); *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,281, at P 585 (2008) ("In fulfilling its responsibilities under sections 205 and 206 of the Federal Power Act, the Commission is required to address, and has the authority to remedy, undue discrimination and anticompetitive effects.").

55 As required by the first step for challenges under section 206 of the FPA, Section I of this filing demonstrates that PJM's current treatment of major maintenance and overhaul costs of CC and CT units is unjust and unreasonable and unduly discriminatory. This Section II demonstrates that PJM's revisions to the Operating Agreement and Tariff are just and reasonable, thus meeting the second step for challenges under FPA section 206, namely proposing a remedy that results in a just and reasonable rate. As PJM also shows in this section II, Tariff revisions proposed here under section 205 of the FPA are just and reasonable. *See* 16 U.S.C. §§ 824d(a) & 824e(a).

Operating Agreement changes must be approved by a two-thirds majority sector vote of the Members Committee, PJM is not authorized to file the Operating Agreement changes under section 205, and therefore instead is submitting them under section 206 in a separate proceeding also being filed this same day. Prior Members Committee approval is not a precondition for filing Tariff changes, which PJM therefore submits under section 205.

Accordingly, PJM requests that the Commission accept, as just and reasonable replacement rules under FPA section 206 to remedy the identified undue discrimination, certain revisions to Operating Agreement, Schedule 2. Specifically, PJM proposes to revise Operating Agreement, Schedule 2, section 1.1(a) by adding "Operating Costs" to the list of recoverable costs in the energy market, and adding new subsections 1.1(d) and (e), reading as follows:[56]

> (d) Operating Costs are expenses related to consumable materials used during unit operation and may include lubricants, chemicals, limestone, trona, ammonia, acids, caustics, water injection, activated carbon for mercury control, and demineralizers usage.
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> (e) Maintenance Adders may include expenses incurred as a result of electric production and can be a function of starts and/or run hours. Allowable expenses include repair, replacement, inspection, and overhaul expenses including variable long term service agreement expenses.[57]

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[56] PJM also proposes certain conforming changes to the Operating Agreement, i.e., updating section references within Operating Agreement, Schedule 2.

[57] PJM seeks acceptance of revisions to the Operating Agreement, Schedule 2, under section 206 only, but is also including a description of its Operating Agreement revisions with its related section 205 filing in the interest of providing the Commission with a full picture of the revisions PJM is proposing to address Variable O&M cost recovery by CC and CT plants in the energy market.

PJM separately proposes, under section 205, a clarification to Tariff, Attachment DD, section 6.8(c) to account for the fact that capacity market offers typically are made years in advance of energy market offers for the same time period. Specifically, Tariff, Attachment DD, section 6.8(c) will be revised to read:

> (c) ~~For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.~~ A Market Seller that intends to recover variable costs under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market may not include such costs under an Avoidable Cost Rate.[58]

These revisions to the Operating Agreement and Tariff will ensure that CT and CC plants are treated on the same basis as all other resource types, with respect to reflecting major maintenance expenses in the calculation of the Maintenance Adder in their cost-based energy market offers. These revisions will not prohibit Generation Resources from continuing to recover major maintenance costs through the capacity market if they choose to do so, provided they are not also planning to recover the same costs in their energy market cost-based offers. These revisions strike an appropriate balance between comparability and cost recovery concerns, ensuring that costs properly categorized as variable can be recovered in the energy market without unduly discriminating against any particular type of Generation Resource.

58 PJM seeks acceptance of revisions to the the Tariff, Attachment DD, under section 205 only, but is also including a description of its Operating Agreement revisions with its related section 206 filing in the interest of providing the Commission with a full picture of the revisions PJM is proposing to address Variable O&M cost recovery by CC and CT plants in the energy market.

Allowing recovery of major maintenance costs in the energy market is consistent with the Commission's regulations across the electricity and natural gas sectors. The Commission has accepted recovery of such costs by combustion turbine and combined cycle plants in the SPP, California, New York, and Midcontinent organized markets, and should do so here.[59] As the Commission has recognized in these cases, certain expenses that can occur at differing times over a multi-year timespan are properly considered variable, and are reasonably included in energy market offers, precisely because the extent of those expenses and when they are incurred depends heavily on how often and for how long a generation resource is operated.

III. EFFECTIVE DATE

As explained above, PJM urges the Commission to issue its final order on this filing by March 31, 2019. A final order by that date would allow PJM sufficient time, if necessary, to submit an appropriate filing to ensure consistency between the energy market rules ordered here and the capacity market parameters that must be posted by no

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59 *See Sw. Power Pool, Inc.*, 165 FERC ¶ 61,026 (allowing recovery through components of the energy market; SPP does not have a capacity market); California Independent System Operator Corporation, Open Access Transmission Tariff, Fifth Replacement FERC Electric Tariff at Section 30.4.1.1.4; *Business Practice Manual for Market Instruments*, California Independent System Operator Corp., Attachment L (Aug. 8, 2018), https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Instruments/BPM_for_Market%20Instruments_V48_redline.pdf; *Reference Level Manual, Manual 34*, New York Independent System Operator, Appendix A (Feb. 2016), https://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/rl_mnl.pdf; *Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,004, at PP 49–50 (2018) (conditionally accepting revisions to MISO's tariff section 64.1.4(a)(iii), which clarify that maintenance costs may be included in the Operating Cost Survey, which is a tool for the MISO market monitor to use to verify that energy offers include only allowable costs).

later than May 1, 2019, for use in the August 2019 Base Residual Auction. PJM accordingly requests that the Commission set March 31, 2019, as the refund effective date required by section 206. Given that the single change proposed under section 205 to Tariff, Attachment DD depends on acceptance of the section 206 change, PJM (in accordance with prior Commission guidance) has given that change "an indeterminate effective date" of 12/31/9998.[60]

IV. CORRESPONDENCE

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

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60 *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,091, at P 1 n.4 (2014).

V. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;
2. Revisions to the Tariff in redlined format as Attachment A;
3. Revisions to the Tariff in clean format as Attachment B; and
4. Mr. Hauske's affidavit as Attachment C.

VI. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[61] 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 Region[62] 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:

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

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

http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

VII. CONCLUSION

Accordingly, PJM requests that the Commission accept, as just and reasonable under section 205, the Tariff changes shown in Attachment A, as described in more detail above.

Respectfully submitted,

/s/ *Paul M. Flynn*

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October 29, 2018

<u>Attachment A</u>

PJM Open Access Transmission Tariff

(Marked / Redline Format)

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Tariff, Attachment M and Attachment - M Appendixand this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) [Reserved for Future Use]

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to Tariff, Attachment DD, section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to Tariff, Attachment DD, section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to Tariff, Attachment DD, section 5.14(h), Tariff, Attachment DD, section 6.5(a)(ii), or Tariff, Attachment DD, section 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Test

(a) [Reserved for Future Use]

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) below that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or market-based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource 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 in the three consecutive calendar years (during the Performance Assessment Intervals in such calendar years) that precede the Base Residual Auction for such Delivery Year), however, for the Base Residual Auction for the 2021/2022 Delivery Year, the Balancing Ratio used in the determination of the default Market Seller Offer Cap shall be 78.5 percent, and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined in Tariff, Attachment DD, section 6.8 below. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7. 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 Tariff, Attachment M-Appendix, section II.E.3.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and documentation required under section 6.7 below to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the 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. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in section 6.7(c) below.

(c) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(d) For any Third Incremental Auction for Delivery Years through the 2017/2018 Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 or 2019/2020 Delivery Years, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Base Capacity resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to the greater of the Net Cost of New Entry times the Balancing Ratio for the relevant LDA and Delivery Year or 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the close of the offer period for the applicable RPM Auction.

(B) Sell Offers based on Planned Generation Capacity Resources (including Planned External Generation Capacity Resources) shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that modeled LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) above are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such

Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) below as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified in writing by 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 and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If such revised Sell Offer is accepted by the Office of the Interconnection, the Office of the Interconnection then shall clear the auction with such revised Sell Offer in place. Pursuant to Tariff, Attachment M-Appendix, Section II.F, the Market Monitoring Unit shall 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.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h) below, all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, section II.C.1, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity

Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under this section 6.6 to establish the maximum EFORd applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum 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, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORd for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORd, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORd, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum 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. As further described in Tariff, Attachment M-Appendix, section II.C, the Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum 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 eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORd or, if no agreement has been reached, specifying the level of alternate maximum EFORd to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORd prior to the specified deadlines, the maximum EFORd for the applicable RPM Auction shall be deemed to be the default EFORd calculated pursuant to this section.

The maximum EFORd that may be used in a Sell Offer for Third Incremental Auction, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate 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 Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORd based on the requirements of the Tariff and the PJM Manuals, per Tariff, Attachment DD, section 5.8, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses for an RPM Auction held prior to the date on which the final EFORd used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, Attachment M-Appendix, section II.C, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (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.

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 Tariff, Part V, section 113.1, 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 Tariff, Part V, section 113.2 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 Tariff, Attachment DD;

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.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year, (b) the September 1 that last precedes the Base Residual Auction for the 2018/2019 and subsequent Delivery Years, and (c) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) Business Days after receipt of any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Tariff, Attachment DD, sections 5.6.6 and this section 6.6 and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of this section 6.6.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource has satisfied the RPM must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Tariff, Attachment M-Appendix, section II.C.4, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the exception request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn’t timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE’s Unforced Capacity Obligation, or any entity’s obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE’s Unforced Capacity Obligation, or any entity’s obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Tariff, Attachment M and Tariff, Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6.

(b) Determinations of EFORd and Unforced Capacity made under this section 6.6 as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource at or below the default Market Seller Offer Cap described in Tariff, Attachment DD, section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting 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 as outlined in Tariff, Attachment M-Appendix, section II.G. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under section 6.6(a) above shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 above and Tariff, Attachment M-Appendix, section II.H.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e) below, in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined section 6.8 below.

Maximum Avoidable Cost Rates by Technology Class								
Technology	**2013/14 Mothball ACR ($/MW-Day)**	**2013/14 Retirement ACR ($/MW-Day)**	**2014/15 Mothball ACR ($/MW-Day)**	**2014/15 Retirement ACR ($/MW-Day)**	**2015/16 Mothball ACR ($/MW-Day)**	**2015/16 Retirement ACR ($/MW-Day)**	**2016/2017 Mothball ACR ($/MW-Day)**	**2016/2017 Retirement ACR ($/MW-Day)**
Nuclear	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pumped Storage	$23.64	$33.19	$24.56	$34.48	$25.56	$35.89	$24.05	$33.78
Hydro	$80.80	$105.67	$83.93	$109.76	$87.35	$114.24	$82.23	$107.55
Sub-Critical Coal	$193.98	$215.02	$201.49	$223.35	$209.71	$232.46	$197.43	$218.84
Super Critical Coal	$200.41	$219.21	$208.17	$227.70	$216.66	$236.99	$203.96	$223.10
Waste Coal - Small	$255.81	$309.83	$265.72	$321.83	$276.56	$334.96	$260.35	$315.34
Waste Coal –	$94.61	$114.29	$98.27	$118.72	$102.28	$123.56	$96.29	$116.32

Large								
Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CC-2 on 1 Frame F	$35.18	$49.90	$36.54	$51.83	$38.03	$53.94	$35.81	$50.79
CC-3 on 1 Frame E/Siemens	$39.06	$52.89	$40.57	$54.94	$42.23	$57.18	$39.75	$53.83
CC–3 or More on 1 or More Frame F	$30.46	$42.28	$31.64	$43.92	$32.93	$45.71	$30.99	$43.03
CC-NUG Cogen. Frame B or E Technology	$130.76	$175.71	$135.82	$182.52	$141.36	$189.97	$133.09	$178.83
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$27.96	$37.19	$29.04	$38.63	$30.22	$40.21	$28.45	$37.85
CT - 1st & Gen. Frame B	$27.63	$36.87	$28.70	$38.30	$29.87	$39.86	$28.11	$37.52
CT - 2nd Gen. Frame E	$26.26	$35.14	$27.28	$36.50	$28.39	$37.99	$26.73	$35.77
CT - 3rd Gen. Aero (GE LM 6000)	$63.57	$93.70	$66.03	$97.33	$68.72	$101.30	$64.70	$95.37
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$33.34	$49.16	$34.63	$51.06	$36.04	$53.14	$33.93	$50.03
CT - 3rd Gen. Frame F	$26.96	$38.83	$28.00	$40.33	$29.14	$41.98	$27.43	$39.52
Diesel	$29.92	$37.98	$31.08	$39.45	$32.35	$41.06	$30.44	$38.66
Oil and Gas Steam	$74.20	$90.33	$77.07	$93.83	$80.21	$97.66	$75.51	$91.94

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them 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. To determine the applicable ACR rates, the Office of the Interconnection shall use 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 ACR rates shall be expressed in dollar values for the applicable Delivery Year.

Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year)		
Technology	**Mothball ACR ($/MW-Day)**	**Retirement ACR ($/MW-Day)**
Combustion Turbine - Industrial Frame	$24.13	$33.04
Coal Fired	$136.91	$157.83
Combined Cycle	$29.58	$40.69
Combustion Turbine - Aero Derivative	$26.13	$37.18
Diesel	$25.46	$32.33
Hydro	$68.78	$89.96
Oil and Gas Steam	$63.16	$76.90
Pumped Storage	$20.12	$28.26

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in Tariff, Attachment M-Appendix, section II.H, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in section 6.8 below, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to Tariff, Attachment M-Appendix, section II.E.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in section 6.4 above). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues: Projected PJM Market Revenues are defined by section 6.8(d) below, for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a 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 representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR + CPQR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

  - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

- **AFAE (Avoidable Fuel Availability Expenses) c**onsists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource

- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer (or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years), such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

  - **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource’s Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the

APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Tariff, Part V. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under Tariff, Attachment DD, section 5.14(c).

- **ARPIR (Avoidable Refunds of Project Investment Reimbursements)** consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Tariff, Part V, section 118 or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Tariff, Part V, section 119 and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) A Market Seller that intends to recover variable costs under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market may not include such costs under an Avoidable Cost Rate.~~For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.~~

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity

Market Seller's fuel and environmental costs for the resource which shall be determined either by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agrement and PJM Manuals that are not fuel or environmental costs.

The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

Attachment B

PJM Open Access Transmission Tariff

(Clean Format)

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Tariff, Attachment M and Attachment - M Appendixand this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) [Reserved for Future Use]

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to Tariff, Attachment DD, section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to Tariff, Attachment DD, section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to Tariff, Attachment DD, section 5.14(h), Tariff, Attachment DD, section 6.5(a)(ii), or Tariff, Attachment DD, section 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Test

(a) [Reserved for Future Use]

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) below that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or market-based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource 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 in the three consecutive calendar years (during the Performance Assessment Intervals in such calendar years) that precede the Base Residual Auction for such Delivery Year), however, for the Base Residual Auction for the 2021/2022 Delivery Year, the Balancing Ratio used in the determination of the default Market Seller Offer Cap shall be 78.5 percent, and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined in Tariff, Attachment DD, section 6.8 below. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7. 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 Tariff, Attachment M-Appendix, section II.E.3.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and documentation required under section 6.7 below to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the 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. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in section 6.7(c) below.

(c) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(d) For any Third Incremental Auction for Delivery Years through the 2017/2018 Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 or 2019/2020 Delivery Years, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Base Capacity resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to the greater of the Net Cost of New Entry times the Balancing Ratio for the relevant LDA and Delivery Year or 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the close of the offer period for the applicable RPM Auction.

(B) Sell Offers based on Planned Generation Capacity Resources (including Planned External Generation Capacity Resources) shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that modeled LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) above are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such

Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) below as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified in writing by 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 and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If such revised Sell Offer is accepted by the Office of the Interconnection, the Office of the Interconnection then shall clear the auction with such revised Sell Offer in place. Pursuant to Tariff, Attachment M-Appendix, Section II.F, the Market Monitoring Unit shall 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.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h) below, all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, section II.C.1, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity

Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under this section 6.6 to establish the maximum EFORd applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum 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, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORd for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORd, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORd, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum 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. As further described in Tariff, Attachment M-Appendix, section II.C, the Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum 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 eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORd or, if no agreement has been reached, specifying the level of alternate maximum EFORd to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORd prior to the specified deadlines, the maximum EFORd for the applicable RPM Auction shall be deemed to be the default EFORd calculated pursuant to this section.

The maximum EFORd that may be used in a Sell Offer for Third Incremental Auction, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate 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 Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORd based on the requirements of the Tariff and the PJM Manuals, per Tariff, Attachment DD, section 5.8, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses for an RPM Auction held prior to the date on which the final EFORd used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, Attachment M-Appendix, section II.C, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (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.

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 Tariff, Part V, section 113.1, 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 Tariff, Part V, section 113.2 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 Tariff, Attachment DD;

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.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year, (b) the September 1 that last precedes the Base Residual Auction for the 2018/2019 and subsequent Delivery Years, and (c) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) Business Days after receipt of any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Tariff, Attachment DD, sections 5.6.6 and this section 6.6 and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of this section 6.6.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource has satisfied the RPM must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Tariff, Attachment M-Appendix, section II.C.4, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the exception request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn't timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Tariff, Attachment M and Tariff, Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6.

(b) Determinations of EFORd and Unforced Capacity made under this section 6.6 as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource at or below the default Market Seller Offer Cap described in Tariff, Attachment DD, section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting 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 as outlined in Tariff, Attachment M-Appendix, section II.G. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under section 6.6(a) above shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 above and Tariff, Attachment M-Appendix, section II.H.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e) below, in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined section 6.8 below.

Maximum Avoidable Cost Rates by Technology Class								
Technology	**2013/14 Mothball ACR ($/MW-Day)**	**2013/14 Retirement ACR ($/MW-Day)**	**2014/15 Mothball ACR ($/MW-Day)**	**2014/15 Retirement ACR ($/MW-Day)**	**2015/16 Mothball ACR ($/MW-Day)**	**2015/16 Retirement ACR ($/MW-Day)**	**2016/2017 Mothball ACR ($/MW-Day)**	**2016/2017 Retirement ACR ($/MW-Day)**
Nuclear	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pumped Storage	$23.64	$33.19	$24.56	$34.48	$25.56	$35.89	$24.05	$33.78
Hydro	$80.80	$105.67	$83.93	$109.76	$87.35	$114.24	$82.23	$107.55
Sub-Critical Coal	$193.98	$215.02	$201.49	$223.35	$209.71	$232.46	$197.43	$218.84
Super Critical Coal	$200.41	$219.21	$208.17	$227.70	$216.66	$236.99	$203.96	$223.10
Waste Coal - Small	$255.81	$309.83	$265.72	$321.83	$276.56	$334.96	$260.35	$315.34
Waste Coal –	$94.61	$114.29	$98.27	$118.72	$102.28	$123.56	$96.29	$116.32

Large								
Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CC-2 on 1 Frame F	$35.18	$49.90	$36.54	$51.83	$38.03	$53.94	$35.81	$50.79
CC-3 on 1 Frame E/Siemens	$39.06	$52.89	$40.57	$54.94	$42.23	$57.18	$39.75	$53.83
CC–3 or More on 1 or More Frame F	$30.46	$42.28	$31.64	$43.92	$32.93	$45.71	$30.99	$43.03
CC-NUG Cogen. Frame B or E Technology	$130.76	$175.71	$135.82	$182.52	$141.36	$189.97	$133.09	$178.83
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$27.96	$37.19	$29.04	$38.63	$30.22	$40.21	$28.45	$37.85
CT - 1st & Gen. Frame B	$27.63	$36.87	$28.70	$38.30	$29.87	$39.86	$28.11	$37.52
CT - 2nd Gen. Frame E	$26.26	$35.14	$27.28	$36.50	$28.39	$37.99	$26.73	$35.77
CT - 3rd Gen. Aero (GE LM 6000)	$63.57	$93.70	$66.03	$97.33	$68.72	$101.30	$64.70	$95.37
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$33.34	$49.16	$34.63	$51.06	$36.04	$53.14	$33.93	$50.03
CT - 3rd Gen. Frame F	$26.96	$38.83	$28.00	$40.33	$29.14	$41.98	$27.43	$39.52
Diesel	$29.92	$37.98	$31.08	$39.45	$32.35	$41.06	$30.44	$38.66
Oil and Gas Steam	$74.20	$90.33	$77.07	$93.83	$80.21	$97.66	$75.51	$91.94

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them 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. To determine the applicable ACR rates, the Office of the Interconnection shall use 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 ACR rates shall be expressed in dollar values for the applicable Delivery Year.

Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year)		
Technology	**Mothball ACR ($/MW-Day)**	**Retirement ACR ($/MW-Day)**
Combustion Turbine - Industrial Frame	$24.13	$33.04
Coal Fired	$136.91	$157.83
Combined Cycle	$29.58	$40.69
Combustion Turbine - Aero Derivative	$26.13	$37.18
Diesel	$25.46	$32.33
Hydro	$68.78	$89.96
Oil and Gas Steam	$63.16	$76.90
Pumped Storage	$20.12	$28.26

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in Tariff, Attachment M-Appendix, section II.H, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in section 6.8 below, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to Tariff, Attachment M-Appendix, section II.E.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in section 6.4 above). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues: Projected PJM Market Revenues are defined by section 6.8(d) below, for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a 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 representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR + CPQR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

    - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

- **AFAE (Avoidable Fuel Availability Expenses) c**onsists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource

- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer (or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years), such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

  - **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the

APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Tariff, Part V. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under Tariff, Attachment DD, section 5.14(c).

- **ARPIR (Avoidable Refunds of Project Investment Reimbursements)** consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Tariff, Part V, section 118 or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Tariff, Part V, section 119 and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) A Market Seller that intends to recover variable costs under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market may not include such costs under an Avoidable Cost Rate.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity Market Seller's fuel and environmental costs for the resource which shall be determined either by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agrement and PJM Manuals that are not fuel or environmental costs.

The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

Attachment C

Affidavit of Thomas M. Hauske

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket Nos. EL19-___-000
	)	ER19-___-000
	)	(Not Consolidated)

AFFIDAVIT OF THOMAS M. HAUSKE
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Thomas M. Hauske. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as Senior Lead Engineer, Operation, Analysis & Compliance, for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of the proposed tariff revisions being filed today by PJM in the captioned proceedings.

Qualifications

2. As a Senior Lead Engineer in PJM's Operation, Analysis & Compliance group, my responsibilities include the review and approval of generating resources' maintenance adders for cost based offers, Fuel Cost Policies, and unit-specific operating parameters adjustment requests. Also, I am a subject matter expert for PJM's cost development guidelines for cost-based offers, combined cycle ("CC") modeling, and black start program.

3. I joined PJM in 2010. Prior to my current position, I worked at Conectiv Energy from 2000 to 2010, first as a Project Engineer, then as a Senior Engineer, and finally as Manager of Technology Services. As Manager of Technology Services, I supervised the Performance Group, System Engineers, Operator Training, and the engineering budget analysts. As a Senior Engineer and Project Engineer, I supported the engineering development and performance acceptance testing of several new CC and peaking facilities, which employed combustion turbines ("CTs"). I also supported performance testing, troubleshooting, and maintenance of Conectiv Energy's existing steam, CC and peaking plants. Prior to my employment at Conectiv Energy, I worked as Performance Engineer for Sithe New England Holdings, LLC from 1998 to 2000 and as an Engineer and Senior Engineer for Boston Edison Company from 1985 to 1998. In these positions I provided engineering support for maintenance and operations of Boston Edison's nuclear, fossil steam, and peaking plants. Sithe New England Holdings, LLC purchased Boston Edison's Fossil units in 1998.

4. I have a Bachelor of Science degree in Mechanical Engineering from Drexel University and Master of Science degree in Mechanical Engineering from Northeastern University. I am a registered Professional Engineer in the State of Pennsylvania and since 2009 have been a member of the Delaware Governor's Council on Boiler Safety.

Introduction

5. PJM's current market rules allow sellers to include a Maintenance Adder in their cost-based energy market offer. That adder permits sellers to account for variable operating and maintenance ("O&M") expenses, but only if those expenses are incurred as a result of electric production. Under PJM's rules, variable maintenance cost is the parts and labor expense of maintaining facilities in satisfactory operating condition. The Maintenance Adder is based on all available maintenance expense history for a period of either ten or twenty years (at the seller's election), and is converted to either an hourly basis using service hours, a MWh basis using historical generation, or a fuel basis using historical fuel burns. While these rules apply to all generation resource types, PJM currently has a separate rule that applies only to CC and CT plants. Maintenance Adders for those plants may not include any expenses for major inspections and overhauls (major maintenance) after June 1, 2015.

6. In this affidavit, I show:

a. There is no reasonable basis for preventing CC and CT plants from including these expenses in their cost-based energy market offers while allowing nuclear and fossil-steam plants to include them in their offers;

b. Generators used in nuclear and steam plants also require periodic major inspections and maintenance, and that maintenance work is not so different from CC and CT major maintenance as to justify a different rule for CC and CT plants' energy market offers;

c. Nuclear and fossil-steam generators in fact include comparable major maintenance expenses in their energy market offers, based on a PJM review of Maintenance Adder calculations I supervised in 2017;

d. Major maintenance costs for CC and CT plants are properly considered variable costs that are incurred as a result of electric production, to the extent (as is often the case) they are based on how often the plants are started, and how long they run;

e. The major manufacturers of the CTs installed in PJM (in both CC and simple cycle configurations) base maintenance requirements, including both hot gas path inspections and major inspections, largely on a combination of unit starts and run hours;

f. Based on my experience with PJM and my experience working with generators, CC and CT plant operators likewise often base their maintenance intervals primarily on unit starts and run hours;

g. In my experience, many CC and CT plant operators in PJM rely on third party firms to provide major maintenance services under long term service agreements ("LTSAs"). These LTSAs typically include regular fixed charges in the nature of stand-by or retainer fees. Those fixed charges should not be included in Maintenance Adders for energy market offers. The largest charges under the LTSAs, however, typically are those incurred when the service firm undertakes major inspection and maintenance activities. Those variable activities typically depend on the number of unit starts and run hours and to that extent are properly considered variable maintenance costs, and should be permitted to be included in Maintenance Adders;

h. PJM's 2012 amendment to Manual 15 to introduce this restriction on CC and CT plant's energy market offers was based on an incorrect view that nuclear and steam plants do not include major maintenance expenses in their energy market offers; and

i. CC and CT plant operators are disadvantaged by the current rules, which require them to recover their major maintenance costs only through three-year forward capacity market offers, introducing a greater risk of under-recovery of these costs in relation to other unit types. Changes in fuel pricing during this time can have a large impact on CC and CT run hours. Energy Market maintenance adders are updated annually and provide other unit types a more reliable method to recover major maintenance costs.

Major Maintenance Activities for CC and CT Plants Are Comparable to Those for Nuclear and Steam Plants

7. There is nothing innate about CT generating equipment that makes its required maintenance uniquely "major" compared to the activities needed to maintain nuclear or fossil boiler or generation plant in satisfactory working order. Major maintenance of a CT generator or the steam turbine generator of a nuclear or fossil boiler requires removal of the casing and repair and replacement of blades, diaphragms, and other turbine components. Major maintenance is typically performed only when the turbine, whether CT or steam turbine, is near or has exceeded an Original Equipment Manufacturer's ("OEM's") recommended operating interval based on either starts or operating hours.

8. Nuclear and fossil-steam plants already include major maintenance expenses in their cost-based energy offers. PJM staff, under my supervision, conducted a review of unit-specific Maintenance Adders submitted in 2017 which included the unit's ten- or twenty-year maintenance cost history and confirmed that such costs have been included by nuclear and fossil-steam plants both before and after PJM's 2012 revisions to Manual 15 that barred inclusion of major inspection and overhaul costs by CC or CT units in their energy market bids. Based on PJM's review of the Maintenance Adder calculations provided by the unit owners in 2017, PJM estimates that up to fifty-three nuclear and steam units included major maintenance in their maintenance history. Some of the unit owners directly stated that major maintenance was included in the history while others showed maintenance expenses spikes (approximately five times greater than

surrounding years) every six to ten years in the history, which typically corresponds to major maintenance.

Major Maintenance Costs for CT and CC Plants Are Properly Considered Variable Costs that Are Incurred as a Result of Electric Production

9. Major maintenance costs for CT and CC plants are properly considered variable costs that are incurred as a result of electric production. Major inspection and overhaul timing is predominantly determined by how often the plant is called upon and for how long the plant operates when called upon. The major OEM's of CTs installed in the PJM Region make this clear. General Electric ("GE"), for example, is the manufacturer of turbines that account for approximately 38% of the CC plant capacity built or under construction in PJM since 2014.[1] In October 2017, GE updated the authoritative guidance document on gas turbine operations and maintenance that, states "GE bases most gas turbine maintenance requirements on independent counts of starts and hours. Whichever criteria limit is first reached determines the maintenance interval."[2] GE made similar statements in its 2009 version of the same guidance document.[3] Similarly, Siemens, the manufacturer of turbine models accounting for another 34% of PJM Region CC capacity over the same time period, offers turbine purchasers generator equipment upgrades to extend intervals for "major inspections" from a typical 50,000 "equivalent baseload hours" or 1,800 "equivalent starts" to 66,000 equivalent baseload hours or 2,400 equivalent starts.[4]

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1 *See* Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters of PJM Interconnection, L.L.C., Docket No. ER19-105-000, Attachment E, Exhibit No. 2 (2018 CONE Study) at 15, Table 6 (Oct. 12, 2018) ("Quadrennial Filing").

2 Justin Eggart, Christopher E. Thompson, Jerry Sasser, Mardy Merrie, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*, GE Power, 5 (Oct. 2017), https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/technical/ger/ger-3620n-heavy-duty-gas-turbine-operationg-maintenance-considerations.pdf.

3 *See* David Balevic, Steven Hartman, Ross Youmans, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*, GE Power, 5 (Nov. 2009), https://www.scribd.com/document/41225485/GER3620L-Nov-3-09b-rev.

4 *Internal Extension – Combustion System Upgrades*, Siemens https://www.siemens.com/global/en/home/products/energy/services/performance-enhancement/modernization-upgrades/gas-turbines/interval-extension-combustion-system-upgrade-sgt-5000f.html (last visited Oct. 26, 2018).

10. These OEM maintenance standards are consistent with my experience with PJM Region CC and CT plant maintenance practices. The recommended maintenance intervals are variable and generally are based on either the unit reaching a total number of operating hours, a total number of starts, or some combination of the two. The size of these maintenance intervals in practice is dependent on electric production and can be difficult to predict with changing market conditions. Maintenance at these OEM-recommended intervals is not a fixed cost because the maintenance does not occur at a defined, uniform interval regardless of operation of the unit. To the contrary, the maintenance interval for CTs varies by usage and maintenance becomes necessary only when the unit is either near or has exceeded the OEM's recommendations.

11. If a CC or CT plant experiences long periods with relatively few hours of electric production compared to the OEM's expectations for usage, such as when it is used for peaking operation, the first major inspection and overhaul could be years later than any calendar-based interval the OEM offers as a reference. On the other hand, if a CC or CT plant experiences periods of frequent electric production, like if it is employed in baseload operation or cycles frequently, major inspection and overhaul could be needed sooner than typically expected.

12. To provide an analogy, this variability in major inspection and overhaul needs for a CC or CT plant is similar to the variability in major maintenance needs for brakes on your car. Brakes are typically designed to operate for a range of driving mileage, such as 30,000 to 40,000 miles. However, if an automobile performs long periods of mostly highway driving, the same brakes could last for 50,000 miles before requiring replacement. However, if the same car experienced frequent quick starts and stops due to urban driving, the same brakes might only last to 15,000 miles. Replacement of automobile brakes therefore is a variable major maintenance expense directly tied to the operation of the vehicle, comparable to a CT unit's major maintenance that is directly tied to its electric production.

Considerations Involving LTSAs

13. Many unit owners with CTs in either simple cycle or CC operation use the OEM to perform the overhaul on the turbine when it reaches a maintenance interval. An LTSA is the contractual agreement between the unit owner and the OEM that describes the scope of work and the associated costs for the work performed by the OEM. These costs can include both fixed and variable costs. The fixed costs are annual payments that the unit owner pays the OEM for the right to have the OEM's services. Variable costs are the repair and replacement costs for OEM repairs and replacement performed during a turbine overhaul. Only the variable costs may be included in a unit's cost based offers. Under the current rules the unit owner must provide the LTSA agreement to PJM and the IMM for review as support in approving the Maintenance Adder. PJM needs this information in order to confirm that the unit owner is only including variable costs in the unit's maintenance history during its annual Maintenance Adder review.

<u>The 2012 Amendments to Manual 15 Do Not Provide a Reason for Continuing to Prevent CC and CT Plants from Including Major Maintenance Costs in Their Energy Market Offers</u>

14. PJM amended Manual 15 in early 2012 to prevent CC plants and CT plants from including major inspection and overhaul expenses in their Maintenance Adders after June 1, 2015. That fact does not justify retaining this restriction. PJM's understanding in 2011 and 2012 was that all other resource types included their comparable major inspection and overhaul expenses in their capacity market offers, rather than in their energy market offers. Because other Manual 15 provisions make clear that maintenance costs included in energy offers cannot be included in capacity offers, PJM thought the change was necessary at that time to put CC plants and CT plants in the same position as all other resource types—including these costs in their capacity offers, but not their energy offers. However, PJM has since learned its factual premise for this prohibition was incorrect: Other resource types do include comparable major inspection and overhaul maintenance expenses in their energy offers. In 2012, unit owners were not required to submit maintenance adder calculation details to PJM for review. PJM only began collecting maintenance adder calculation details as a result of Commission proceedings in Docket No. ER16-372 that established the requirement for PJM to collect such information from Market Sellers.[5] Based on PJM's review of the maintenance adder information submitted to it in 2017, it is now clear that other resource types appropriately include major maintenance expenses in their energy market offers.

<u>Operators of CT and CC Plants Are Unfairly Disadvantaged by Being Prevented from Including Major Maintenance Costs in Energy Market Offers</u>

15. For CC and CT plants, major inspection and overhaul expenses typically make up a majority of the costs that are incurred both to maintain facilities in satisfactory operating condition and as a result of electric production. For example, in the study provided to support PJM's Quadrennial review recently filed with FERC, PJM's independent consultants estimated variable O&M to be $6.93 per MWh, based on $5.83 per MWh for major maintenance and only $1.10 for other variable O&M.[6]

16. It is challenging to estimate these costs accurately for a capacity market offer three years in advance of a Delivery Year because it is hard to predict how often and for how long such plants will be operated during a future year. Future fuel pricing volatility can have a large impact on the annual operating hours of a CC or CT plant. CC and CT plants' major maintenance costs can be more reliably estimated as part of offers

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5 *See PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,133, at PP 50–58 (2017); *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,282, at P 63 (2016); Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER16-372-003, at 8–10, 19–20 (Mar. 6, 2017).

6 *See* Quadrennial Filing, Attachment E at P 22.

into the energy market, which has a much shorter time horizon between bids and performance.

17. This concludes my Affidavit.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket Nos. EL19-___-000
	)	ER19-___-000
	)	(Not Consolidated)

VERIFICATION

Thomas M. Hauske, being first duly sworn, deposes and states that he is the Thomas M. Hauske referred to in the foregoing document entitled "Affidavit of Thomas M. Hauske," 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.

T M Hauske

Subscribed and sworn to before me, the undersigned notary public, this 26th day of October 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