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October 9, 2014

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

Re: ***PJM Interconnection, L.L.C.*, Docket No. ER15-68-000**
Updates To Costs of New Entry For The Minimum Offer Price Rule

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, hereby submits revisions to the PJM Open Access Transmission Tariff ("Tariff") to update the new entry cost estimates for both a combined cycle ("CC") generation plant and a combustion turbine ("CT") generation plant that are used to set the Minimum Offer Price Rule ("MOPR") Floor Offer Price.[1]

PJM requests that the enclosed revisions become effective on December 8, 2014, which is 60 days after the date of this filing.

I. BACKGROUND

A. PJM Has Completed a Detailed Review of the Costs to Construct Combustion Turbine and Combined Cycle Generation Plants in the PJM Region, and Has Filed Changes to the Cost of New Entry Used in the Variable Resource Requirement Curve As a Result of That Review.

PJM is required by its Tariff to review periodically the Variable Resource Requirement ("VRR") Curve[2] that is used to clear capacity auctions, as well as the key inputs to that curve, including the Cost of New Entry ("CONE")[3] by a representative new

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1 Capitalized terms not otherwise defined herein have the meaning specified in the Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region.

2 Tariff, Attachment DD, sections 5.10(a)(i) – (iii).

3 *Id.*, Attachment DD, section 5.10(a)(iv).

power plant. PJM retained an independent consultant, The Brattle Group ("Brattle") to assist with the 2014 periodic review; the results of Brattle's detailed review of the CONE are reflected in their report, "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM" ("2014 CONE Study").

Based on Brattle's work and PJM's own analyses, PJM staff advised stakeholders in May 2014 of PJM's recommended changes to the VRR Curve parameters, including the CONE. PJM and its stakeholders then devoted several months to intensive discussion of these issues. While MOPR is not part of the required periodic review, the stakeholder discussions included conforming changes to the new entry costs used in MOPR, recognizing the need for consistency between the CONE used in the VRR Curve and the new entry cost estimates used as an offer screen in MOPR.

The periodic review of the VRR Curve culminated with PJM's September 25, 2014 filing in Docket No. ER14-2940-000 ("VRR Curve Review Filing") of proposed changes to the VRR Curve and its parameters, including the CONE for a representative CT plant, for implementation in connection with the May 2015 Base Residual Auction ("BRA") for the 2018/2019 Delivery Year.

B. The same Gross CONE estimates used to establish the VRR Curve are used to determine the Net Asset Class CONE for the Minimum Offer Price Rule Floor Offer Price.

MOPR uses new entry cost estimates for three gas-fired resource types—CT, CC, and Integrated Gasification Combined Cycle ("IGCC")—to calculate Net Asset Class CONEs for each of those resource types. Sell offers from those resource types are then compared against the Net Asset Class CONEs to identify offers that require case-specific review to guard against below-cost new-entry offers. Specifically, PJM uses the Net Asset Class CONE for each CONE Area to establish the MOPR Floor Offer Price for each CONE Area.[4]

As the Commission has recognized, the MOPR uses "the same basic methodology [to calculate new entry costs] for CT and CC units that PJM uses to produce the Net CONE for a CT for RPM's Variable Resource Requirement Curve."[5] Given this dual use of new entry cost estimates in the Reliability Pricing Model ("RPM"), the Commission has repeatedly found that "the MOPR values should be updated to be in line with the Variable Resource Requirement Curve values."[6]

[4] Tariff, Attachment DD, section 5.14(h)(3).

[5] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 46 (2011).

[6] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 45 (2011) (citing *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275 at P 192 (2009)). *See also PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at PP 24-33 (2011).

Consistent with the changes to CONE proposed in the VRR Curve Review Filing, and with the recognized need for conforming changes to MOPR in the recently concluded VRR Curve Review stakeholder process, PJM is filing in this proceeding to change the CC and CT new entry cost estimates used in MOPR to be consistent with those proposed in the VRR Curve Review Filing. PJM clarifies that, although filed separately, PJM does not intend the new entry cost estimates resulting from this proceeding to depart from those approved in the proceeding on the VRR Curve Review Filing. PJM would accept a condition to that effect in any Commission order on this filing.

II. PROPOSED TARIFF REVISIONS

A. Update to MOPR Asset Class CONE Estimates.

By this filing, PJM updates both the CT and CC new entry cost estimates used in MOPR.[7] In support of these changes, this filing includes the affidavit of Dr. Samuel A. Newell ("Newell Affidavit"), a Principal at Brattle who led Brattle's review of CONE and the other VRR Curve parameters, and the affidavit of Dr. Paul M. Sotkiewicz ("Sotkiewicz Affidavit"), PJM's Chief Economist. This filing also includes a copy of the 2014 CONE Study, as an attachment to Dr. Newell's affidavit.

In the 2014 CONE Study, Brattle performed detailed engineering estimates of the costs to construct representative new entry projects in the PJM Region, for both CT and CC plants.[8] To this end, Brattle first defined each plant on which the estimate would be based. For the CT, Brattle assumed a generation plant configured with two General Electric Frame 7FA turbines with inlet air cooling and selective catalytic reduction ("SCR") nitrogen oxide ("NOx") emissions control technology.[9] For the CC plant, Brattle identified a single heat recovery steam generator and steam turbine configuration, i.e., "a 2×1 configuration," as the representative technology, consistent with the predominant plant type among recent CC additions in PJM.[10] The representative CC employed the latest General Electric Frame 7FA turbine (i.e., the same turbine as used in the CT plant design, and on which all prior RPM CONE estimates have been based).[11]

7 As this filing is prompted by the Brattle review and report on the CT and CC CONE values, PJM is not proposing any changes to the IGCC new entry cost estimate at this time. PJM will file any changes to the IGCC CONE as and when warranted through a separate filing.

8 Newell Affidavit at 3; *see also* VRR Curve Review Filing at 23-24.

9 2014 CONE Study at iii, 8, 12-13.

10 2014 CONE Study at iii, 8-10.

11 *See* Tariff, Attachment DD, section 2.58 (defining Reference Resource as a CT plant "configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology . . . , dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh").

Like the CT Reference Resource and consistent with most recently built CC plants, Brattle's CC reference resource uses SCR NOx emission control technology.[12]

Based on these configurations, Brattle then estimated the fixed capital costs of constructing the project and placing it in service in time for the 2018/2019 Delivery Year, and the fixed operations and maintenance ("O&M") costs over the project's assumed economic life. The estimated capital costs include, for example, the turbine and associated equipment typically sold as a package by the vendor, other major materials, land, station equipment, buildings, necessary gas pipeline and electric transmission infrastructure, emissions control equipment, permitting costs, and any contingency. The ongoing fixed O&M expenses include, for example, labor, outside contractor costs for operations or maintenance, property taxes, insurance, overheads, and regulatory expenses. The estimated new entry cost in each case was developed using a financial model that includes estimates of the likely debt cost, required internal rate of return, income taxes, and the project's economic life.

While PJM relies on the 2014 CONE Study to support the CT and CC values filed in this proceeding, PJM has made one adjustment, not reflected in the 2014 CONE Study, to derive the proposed cost estimates in this filing. PJM also departs from Brattle's recommendations on two other issues that affect the estimated new entry costs; however, in those two cases, Brattle included alternative calculations in the 2014 CONE Study showing the effect of adopting the PJM position on those issues.

First, during the stakeholder process, the Independent Market Monitor for PJM ("IMM") and its consultants, Pasteris Energy and Stantec Consulting Services, provided alternative estimates of the cost of labor to construct the new entry plants. Upon review, PJM determined that those estimates provided a reasonable alternative to the labor cost estimates in the 2014 CONE Study, and decided to utilize the IMM estimates. As Dr. Sotkiewicz explains in his affidavit, before adopting the IMM's labor cost estimates, PJM carefully considered publicly available data on wage rates, examined and benchmarked labor estimates from previous CONE studies, and consulted with Sargent & Lundy—the Brattle subcontractor that prepared the labor cost estimates in the 2014 CONE Study—regarding labor costs and regional variations in construction labor productivity.[13]

As detailed in his affidavit, Dr. Sotkiewicz calculated alternative construction labor cost estimates for each CONE Area, based largely on the Pasteris/Stantec estimates, supplemented with public data on utility system construction wages and information from the 2011 and 2014 CONE studies for PJM.[14] PJM's labor cost estimates were then

[12] 2014 CONE Study at iii, 13-16.

[13] Sotkiewicz Affidavit at ¶¶ 16-21.

[14] Sotkiewicz Affidavit at ¶¶ 21-27.

provided to Brattle, for inclusion in their calculations of the CT and CC CONEs, which are the basis for the MOPR CC and CT estimates proposed in this filing.[15]

Second, Dr. Sotkiewicz explains that, in another departure from Brattle's recommendations, PJM is maintaining its Commission-accepted practice of using the "nominal levelized" financial model to determine the new entry costs, rather than adopting the "real levelized" approach.[16] The Commission has previously accepted use of the nominal levelized approach in RPM as just and reasonable, and has rejected attempts by protestors to compel PJM to base generic CONE values (such as those used in the VRR Curve) on the real levelized basis.[17] Particularly relevant to this proceeding, the Commission has specifically found that "for the purpose of calculating [a MOPR] offer floor, the nominal levelized method is reasonable."[18] Accordingly, the values PJM is proposing in this filing are based on the nominal levelized approach.

Finally, PJM also declines to adopt Brattle's recommendation that the CT and CC CONE estimates for CONE Area 3: Rest of Market omit the costs of dual-fuel capability. The current Tariff expressly defines RPM's Reference Resource as a CT plant that includes dual-fuel capability in all five current CONE Areas and PJM is not amending that approved Tariff provision to eliminate dual-fuel capability.[19] While Brattle assumed the CONE Area 3: Rest of RTO to be single-fuel, at PJM's request, Brattle also calculated CONE estimates with dual-fuel capability for both CT and CC plants for CONE Area 3.[20] For CC plants in CONE Area 2: Southwestern Mid-Atlantic Area

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[15] *See* Newell Affidavit at 4.

[16] Sotkiewicz Affidavit at ¶¶ 5-15. As explained by the Commission, the real levelized approach:

> produces lower numbers in the early years of a project's life and higher numbers in the later years [compared to nominal levelized], by assuming that plant revenue requirements will increase each year to reflect a 2.5 percent annual increase in operating expenses.

PJM Interconnection, L.L.C., 135 FERC ¶ 61,022, at P 34 n.28 (2011).

[17] *Id.* at PP 49-51.

[18] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 32; *see also id.* ("the nominal levelized method is a just and reasonable method of modeling a competitive bid . . . because it is a reasonable method of modeling a competitive first-year offer based upon typical cash flow streams associated with financing [and] is consistent with the VRR Curve parameters, as well as the mortgage-like cash stream associated with project finance, and therefore, its use for the MOPR benchmark is reasonable.").

[19] This issue is also discussed in the VRR Curve Review Filing, at section II.C.4.c.

[20] 2014 CONE Study at 13, 44.

Council (SWMAAC), however, PJM accepts Brattle's recommendation to assume firm natural gas transportation, rather than dual-fuel capability. This assumption is consistent with the projects currently in development and the constrained pipeline capacity in the area.[21]

Thus, as discussed in Dr. Newell's affidavit, based on the detailed analysis in the 2014 CONE Study and PJM's supplemental analyses and requested changes, Brattle calculated the June 1, 2018 new entry cost estimates for the CC plant in each CONE Area as follows:[22]

Table 1
Proposed Gross CC CONE values

CONE Area	CC Level-Nominal Gross CONE *($/MW-y)*[23]
CONE Area 1	$185,700
CONE Area 2	$176,000
CONE Area 3	$172,600
CONE Area 4	$179,400

21 2014 CONE Study at 14, 31.

22 Newell Affidavit at 4-5.

23 Consistent with PJM's proposal in the VRR Curve Review Filing to eliminate CONE Area 5 and merge it with CONE Area 3, *see* VRR Curve Review Filing at 24-25, PJM is proposing to eliminate CONE Area 5 from its table listing the Gross CONE values used to determine Net Asset Class CONE. *See* Tariff, Attachment DD, proposed section 5.14(h)(3). For informational purposes, however, PJM notes that Brattle, using the same methodology as for the remaining CONE Areas (including the changes requested by PJM, as detailed by Dr. Sotkiewicz), estimated the Gross CONE value for a CC in Cone Area 5 to be $164,200 per MW-year. *See* Newell Affidavit at 5.

Using the same approach and assumptions, Brattle calculated the June 1, 2018 new entry cost estimates for the CT plant in each CONE Area as follows:

Table 2
Proposed Gross CT CONE values

CONE Area	CT Level-Nominal Gross CONE *($/MW-yr)*[24]
CONE Area 1	$132,200
CONE Area 2	$130,300
CONE Area 3	$128,900
CONE Area 4	$130,300

These CT values are the same as those filed by PJM in the VRR Curve Review Filing.

Accordingly, given the new detailed estimates provided in the 2014 CONE Study for both a CT and CC plant and the Commission's finding that MOPR Net Asset Class CONE values "should be updated to be in line with the Variable Resource Requirement Curve values,"[25] PJM is updating the Net Asset Class CONE values in the MOPR for both a CC and CT plant to reflect those set forth in Tables 1 and 2 above.[26]

B. PJM Is Making One Change to the MOPR's Current Cross-Reference to the Index-Adjustment Method Used for the VRR Curve CONE.

PJM is not changing MOPR's current express cross-reference to, and reliance on, the construction cost indexing method specified in the VRR Curve tariff sections.[27] Any change to the indexing method, such as that proposed by PJM in the VRR Curve Review Filing, will therefore automatically apply to the MOPR and will be used to determine the new entry cost estimates for Delivery Years between comprehensive updates to the estimates—but with one supplemental reference to ensure the CC costs are properly updated. The VRR Curve Review Filing proposes to use a composite index for the index adjustment, with weightings for the component individual indices based on their cost categories' relative contributions to the new entry cost. PJM has proposed to state those weightings in the Tariff provision on the VRR Curve, but those stated weightings are

[24] Brattle also estimated the Gross CONE value for a CT in CONE Area 5 to be $126,400/MW-yr. *See* Newell Affidavit at 5.

[25] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 45.

[26] *See* Tariff, Attachment DD, proposed section 5.14(h)(3).

[27] *See id.*, Attachment DD, section 5.14(h)(3)(i) ("the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B)").

based on the CT CONE. Therefore, PJM is adding a proviso to the MOPR cross-reference to the VRR Curve CONE index adjustment method to state the different weightings that will be used for the composite index for the CC CONE. Dr. Sotkiewicz describes and supports these CC weightings in his affidavit.[28]

C. All Changes Proposed in this Filing Are to Be Effective Starting With the 2018/2019 Delivery Year and Will Not Disturb the 2015/2016, 2016/2017, and 2017/2018 Delivery Years.

As with the Tariff changes in the VRR Curve Review Filing, PJM is proposing to implement the changes proposed here starting with the 2018/2019 Delivery Year and for all subsequent Delivery Years. The current-effective Tariff rules related to the MOPR Asset Class Net CONE will remain in effect through the end of the 2017/2018 Delivery Year, and will govern issues related to Delivery Years prior to the 2018/2019 Delivery Year, including any Incremental Auctions conducted for Delivery Years prior to the 2018/2019 Delivery Year. Thus, the MOPR Asset Class CONE values determined for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years will continue in effect for the respective Delivery Years. The Tariff revisions PJM is proposing clearly specify this delineation and state that the changes proposed in this filing apply only beginning with the 2018/2019 Delivery Year and all subsequent Delivery Years.[29]

III. EFFECTIVE DATE

The enclosed revisions incorporate an effective date of December 8, 2014, which is 60 days after the date of this filing.

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28 Sotkiewicz Affidavit at ¶ 32 and Table 3.

29 *See id.*, Attachment DD, proposed section 5.14(h)(3) ("For purposes of the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year.").

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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V. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;

2. Revisions to the PJM Tariff (in redlined and non-redlined format (as Attachments A and B, respectively) and in electronic tariff filing format as required by Order No. 714);

3. Affidavit of Dr. Paul M. Sotkiewicz on behalf of PJM, as Attachment C; and

4. Affidavit of Dr. Samuel A. Newell with attached resume and 2014 CONE Study, as Attachment D.

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,[30] 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[31] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

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

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

VII. CONCLUSION

Accordingly, PJM requests that the Commission accept the enclosed Tariff revisions effective December 8, 2014.

Respectfully submitted,

/s/ *Paul M. Flynn*

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October 9, 2014

Attachment A

Revisions to the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

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

b) Resource Make-Whole Payments

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

c) New Entry Price Adjustment

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

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

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

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

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

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

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section

5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

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

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

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

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

d) Qualifying Transmission Upgrade Payments

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

e) Locational Reliability Charge

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

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

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

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

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

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

g) Resource Substitution Charge

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

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

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

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

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

(3) *MOPR Floor Offer Price.* The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years~~commencing on June 1, 2015~~, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), a combined cycle generator ("CC"), and an integrated gasification combined cycle generator ("IGCC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	~~CONE Area 5~~
CT $/MW-yr	132,200~~140,000~~	130,300~~130,600~~	128,900~~127,500~~	130,300~~134,500~~	~~114,500~~
CC $/MW-yr	185,700~~173,000~~	176,000~~152,600~~	172,600~~166,000~~	179,400~~166,000~~	~~147,000~~
IGCC $/MW-yr	582,042	558,486	547,240	537,306	~~541,809~~

i) Commencing with the Delivery Year that begins on June 1, ~~2016~~2019, the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above, except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3,198 per MW-year.

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

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

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

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

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

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

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

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

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

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

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

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

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

vi*i*) For purposes of the Self-Supply Exemption:

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

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

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

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

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

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

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

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

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

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

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

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

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

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened

Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

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

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

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request *satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.*

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

(*9*) <u>*Exemption/Exception Process*</u>*.*

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

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

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

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

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

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

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

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

i) Capacity Export Charges and Credits

(1) Charge

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

(2) Credit

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

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

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

Where:

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

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

(3) Distribution of Revenues

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

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

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

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

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

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

   DRTC = (IAP – BRP) * DRMW

   Where:

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

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

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

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

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

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

C. A Qualified DR Provider may seek compensation related to its previously cleared

Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this Transition Provision, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

   a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

   b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

   c. an aggregate amount that exceeds:

      (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

      (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

      (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

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

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

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

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

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

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii-*l*) and 5.12(b)(iii-*1*) of this Attachment DD.

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

Attachment B

Revisions to the
PJM Open Access Transmission Tariff

(Clean Format)

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

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

b) Resource Make-Whole Payments

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

c) New Entry Price Adjustment

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

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

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

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

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

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

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section

5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

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

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

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

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

d) Qualifying Transmission Upgrade Payments

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

e) Locational Reliability Charge

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

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

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

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

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

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

g) Resource Substitution Charge

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

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

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

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

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

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

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

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

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above, except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3,198 per MW-year.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

vi*i*) For purposes of the Self-Supply Exemption:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, *over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.*

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

(*9*) Exemption/*Exception* Process.

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

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

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

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

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

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

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

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

i) Capacity Export Charges and Credits

(1) Charge

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

(2) Credit

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

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

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

Where:

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

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

(3) Distribution of Revenues

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

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

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

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

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

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

    DRTC = (IAP – BRP) * DRMW

    Where:

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

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

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

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

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

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

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

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this Transition Provision, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

   a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

   b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

   c. an aggregate amount that exceeds:

      (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

      (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

      (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

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

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

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

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

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

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii-*l*) and 5.12(b)(iii-*1*) of this Attachment DD.

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

Attachment C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. **)** **Docket No. ER15-**68-000

AFFIDAVIT OF DR. PAUL M. SOTKIEWICZ
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Dr. Paul M. Sotkiewicz, and I am the Chief Economist in the Market Service Division of PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit in support of PJM's proposed update to the estimated costs to construct a new combustion turbine ("CT") power plant and a new combined cycle ("CC") power plant, for use as an offer screening parameter in the Minimum Offer Price Rule ("MOPR") of PJM's capacity market, known as the Reliability Pricing Model ("RPM"). While PJM primarily relied on The Brattle Group ("Brattle") to develop these cost estimates, PJM departed from Brattle's recommendations in a few respects, as I explain in this affidavit.

2. As the Chief Economist at PJM, I provide expert analysis, advice, and support for PJM initiatives related to market design changes in, and performance of, PJM's energy, ancillary service, and capacity markets. In particular, I have worked extensively on demand response mechanisms, the development of shortage pricing mechanisms to comply with the Commission's Order No. 719, the integration of intermittent renewable resources into PJM's markets, market power mitigation issues, and, as related to this proceeding, changes to RPM. Additionally, I provide expert analysis on major policy issues facing PJM and have led research efforts that have resulted in whitepapers on the impact of potential climate change policies on PJM's energy markets, transmission cost allocation methods used here and abroad, and the effect of EPA's Cross State Air Pollution Rule and National Emissions Standards for Hazardous Air Pollutants on potential coal capacity retirements in the PJM region. Prior to joining PJM, I served as the Director of Energy Studies at the Public Utility Research Center, University of Florida and as an Economist at the Federal Energy Regulatory Commission. I have a B.A. in History and Economics from the University of Florida, and an M.A. and Ph.D. in Economics from the University of Minnesota.

3. In October of 2013, PJM retained The Brattle Group to review the Cost of New Entry ("CONE") parameters of RPM, as required periodically under PJM's tariff. The results of that review are set forth in a report entitled "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM with June 1, 2018 Online Date" ("2014 CONE Study"). On September 25, 2014, PJM filed in Docket No. ER14-2940-000 revised CT CONE values (based largely on the 2014 CONE Study) for use in determining the RPM Variable Resource Requirement ("VRR") Curve. I submitted an affidavit in Docket No. ER14-2940-000 to identify, and support, certain areas in which PJM departed from Brattle's recommendations concerning the CT CONE estimates in the 2014 CONE Study.

4. In this proceeding, PJM is filing changes to the CT and CC new entry cost estimates used in the MOPR, again based largely on the 2014 CONE Study. The CT values presented here are the same CT values PJM filed in Docket No. ER14-2940-000 for the VRR Curve, and the CC values, like the CT values, also were calculated from the 2014 CONE Study and also reflect certain changes requested by PJM. Dr. Samuel A. Newell of Brattle is submitting an affidavit in this proceeding in which he summarizes the methodology and results of the 2014 CONE Study, and notes the elements of the estimates changed at PJM's request. In my affidavit, I identify and support two elements of the CT and CC cost estimates on which PJM departed from Brattle's recommendations, i.e., 1) continuing to use a nominal levelized approach to calculating the annual revenue requirements; and 2) adopting an alternative estimate of labor costs, based on estimates first developed by the Independent Market Monitor for the PJM Region ("IMM").

A. **Use of the Nominal Levelized Financial Modeling Method to Calculate MOPR Screening Values.**

5. Translating project investment and fixed operations and maintenance costs for new generation resources over the expected economic life of the resource into a levelized annual cost is standard practice in the utility industry. The levelized annual cost provides information to the project developer, regulators, and counterparties concerning the constant stream of revenues needed each year to cover the cost of the project including returns on capital. That constant stream of payments can be expressed in either "real" or "nominal" terms.

6. Expressing the constant stream of payments in nominal terms ("nominal levelized") means that the payment in each year is the same regardless of inflation. Under nominal levelized, the project developer would receive the same dollar amount (e.g. $120,000/MW-year) in each year over the life of the project regardless of the assumed rate of inflation over the life of the project.

7. Expressing the constant stream of payments in real terms ("real levelized") means that the payment each year, while the same on an inflation-adjusted basis, increases each year over the life of the project by the rate of inflation.

8. For any given assumed rate of inflation, the present value of the stream of payments under either nominal levelized or real levelized is exactly the same. What differs is the trajectory of the payments in nominal terms. Figure 4 from Brattle's 2014 report on the VRR Curve and its parameters,[1] reproduced below, illustrates this, showing nominal levelized cost recovery as a flat line and real levelized cost recovery as a line that increases over the life of the project.

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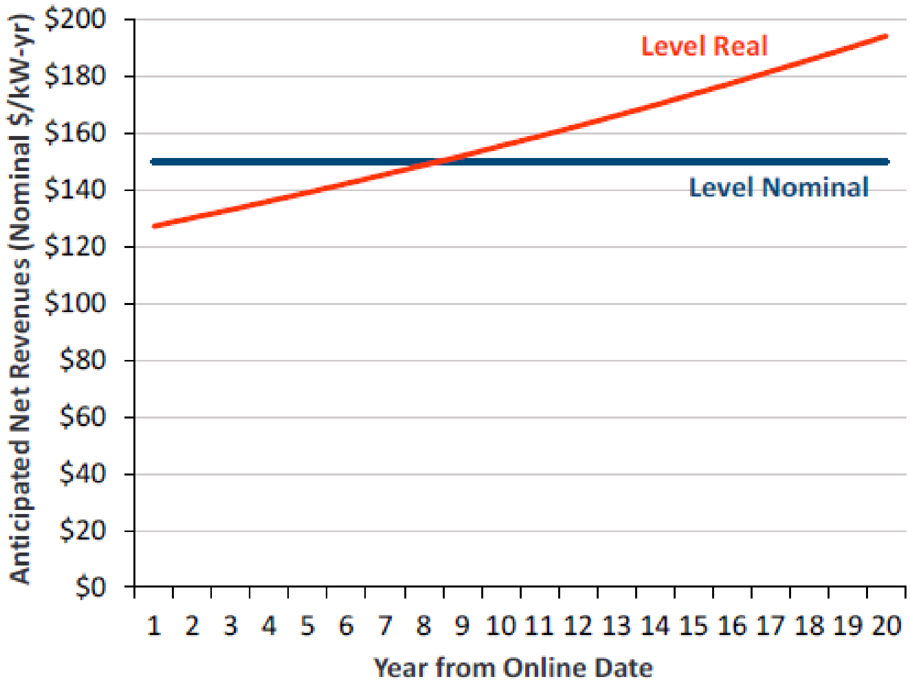
[1] Brattle's 2014 report on the VRR Curve was included in PJM's filing in Docket No. ER14-2940-000 as an attachment to the Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees and is also available on the PJM website at: *http://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-vrr-curve-report.ashx*.

9. As can be seen, the payments made in the early years under nominal levelized cost recovery are greater than the payments in the early years under real levelized cost recovery. However in the later years the nominal levelized payments are less than the real levelized payments. Thus, nominal levelized payments recover more of the project cost in the early years and less of the project cost in later years. Conversely, real levelized payments recover less of the project cost in the early years and more of the project cost in the later years of the project.

Figure 4
Assumed Cost Recovery Profile under Level-Real and Level-Nominal Levelization
(EMAAC Combustion Turbine, Online June 1, 2018)



Sources and Notes:
Values reflect anticipated cost recovery profile for EMAAC CT, consistent with our updated CONE estimates from Table 1 and Newell, *et al.* (2014a).

10. In 2011, the Commission approved using the nominal levelized approach to determine the MOPR screening values. The Commission found that, even with a gross CONE escalation rate of only 2.5 percent under the real levelized method, the energy service revenue offset and other factors would imply an effective inflation rate of 6.0 percent, which the Commission found to be an unreasonable expectation to ascribe to a developer.[2] By contrast, the Commission found that it would be reasonable for a developer to use a nominal levelized approach, since it matches the mortgage style financing that is typical for new generation projects.[3]

2 *PJM Interconnection L.L.C.* 135 FERC ¶ 61,022 at P 50 (2011).

3 *Id.* at P 51.

11. In connection with preparation of its CONE estimate for the VRR Curve, Brattle recommended that PJM and its stakeholders consider transitioning from the nominal levelized method to a real levelized approach. Brattle's recommendation was based on the idea that the CONE will increase at the rate of inflation or more over time and that in the long run future net revenues accruing to merchant investment will be set by the CONE of a future new entrant.

12. In my view, the issue here is not whether it is reasonable to project that revenues based upon CONE will steadily increase every year at a particular inflation rate. The issue is whether it is *unreasonable* to expect that a *merchant developer* will want the assurance of a constant revenue stream (on a nominal levelized basis) in order to go forward with a new entry project. There are ample reasons to expect that a developer might be wary of the risks implicit in a real levelized model, and thus it is not unreasonable to expect a developer would want a constant revenue stream. In other words, a developer legitimately might decline to invest if it is at risk of not receiving the annual revenue increases on which the nominal levelized model depends.

13. Brattle's preference for a real levelized approach assumes that generation project developers are risk neutral rather than risk averse, especially with respect to adverse shocks that can reduce revenues for an extended period of time. But it is reasonable to expect that project developers are risk averse for a host of reasons, including inflation uncertainties and future revenue uncertainties attributable to various demand, supply, or policy shocks that are difficult to predict. Project developers that are risk averse may prefer to receive a greater share of cost recovery in the early years of the project's life given that forecasts about future market conditions and policies affecting the industry 5, 10, 15, and 20 years forward grow ever more uncertain. Absent certainty about the future stream of payments, project developers likely could well prefer to recover project investment costs in the early years of the project rather than in later years.

14. The nominal levelized approach also has other advantages that support its use here as a reasonable reflection of likely developer behavior. From a real options theory perspective, the choice of nominal levelized CONE reduces the value of waiting for more information about the effect of shocks to the wholesale energy and capacity markets before making a new investment, and thus is more compatible with timely new entry. From a reliability (resource adequacy) perspective, providing greater certainty about revenues early in the project life through nominal levelization will be more likely than real levelization to attract new entry when it is actually needed precisely because merchant project developers are operating in an uncertain environment and thus may be more inclined to be risk averse. If CONE were set in the Tariff and VRR Curve at the real levelized value (i.e., with lower early-year payments), generation developers that are risk averse would be more likely to offer new entry projects in RPM only at prices *above* the tariff-specified Net CONE. This implies new entry would only take place when installed reserve margins are below the installed reserve margin implied by the VRR Curve,

regardless of the shape or position of the VRR Curve.[4] From a PJM perspective as the entity responsible for ensuring resource adequacy, the power industry is facing a great deal of uncertainty regarding supply and demand fundamentals and policy direction. As I explained in my affidavit in Docket No. ER14-2940-000, moving toward a real levelized CONE could easily result in an erosion of the performance of RPM to maintain resource adequacy reliability at the target installed reserve margin in the face of fundamentals and policy outcomes that could significantly reduce supply.[5]

15. These considerations that support the use of the nominal levelized approach in the VRR Curve also support its use to calculate the minimum screening price in MOPR. An *individual* developer *could* have project-specific reasons for accepting lower payments in the early years of its project, but a real levelized minimum screening price assumes *every* developer will accept lower early-year payments, by assuming that real nominal offers are presumptively competitive and do not require project-specific review. But that assumption plainly will not be true in every case, since many new entry developers may indeed be risk-averse. Consequently, a real levelized screening price could allow some offers that do not qualify for the MOPR's stated exceptions, but that are *not* competitive, to escape review. Conversely, a nominal levelized screen will ensure review of those offers, but will also allow developers that have legitimate reasons for preferring a real-levelized approach to support that preference in the project-specific review. Accordingly, the minimum offer screening price used in MOPR should be calculated using nominal levelization.

B. <u>PJM Adoption of the IMM Construction Labor Costs for Determining the CT and CC MOPR Screen Values.</u>

16. PJM is revising the CT and CC new entry cost estimates contained in the 2014 CONE Study to include an alternative estimate of the costs of construction labor, incorporating and extending work originally presented in the triennial review stakeholder process by the Independent Market Monitor for the PJM Region ("IMM").[6] These alternative estimates are reasonable, based on my review (discussed below) of publicly available data on construction labor wage rates, construction labor cost estimates from the independent expert CONE study prepared for PJM in 2011 as part of the last triennial review, and elements of the Sargent & Lundy construction labor cost analysis in the 2014 CONE Study.

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4 Under the current VRR Curve, the installed reserve margin ("IRM") implied by Net CONE is the target IRM plus 1%, and under the proposed VRR Curve filed under ER14-2940-000 it is the target IRM +2%.

5 *See* Submittal of PJM Interconnection, L.L.C., Docket No. ER14-2940-000, at Attachment C, Affidavit of Dr. Paul M. Sotkiewicz, at ¶¶ 25-26 (Sept. 25, 2014) (citing Brattle's 2014 report on the VRR Curve at 11).

6 *See* Pasteris Energy, Brattle CONE Combustion Turbine Revenue Requirements Review for Monitoring Analytics, LLC, July 25, 2014, posted at http://pjm.com/~/media/committees-groups/task-forces/cstf/20140725/20140725-brattle-vs-ma-som-cone-ct-revenue-requirements-comparison-final-report.ashx.

17. The IMM presented its alternative construction labor cost estimates based on work by a consultant, Pasteris Energy, which the IMM retains to develop generation new entry revenue requirements for use in the IMM's annual state of the market reports. Pasteris Energy in turn retained Stantec Consulting Services, Inc. ("Stantec") to develop the "plant proper" capital cost component of the cost estimate.[7] For a CT plant built in CONE Area 1 (assumed to be in New Jersey), Stantec estimated 360,000 hours of construction labor at an average labor rate of $86/hour[8] for a labor construction cost of $31.0 million in 2013 dollars. Stantec then escalated those labor costs at a rate of 3.75% per year to arrive at a 2018 labor construction cost estimate of $37.3 million for the CT in CONE Area 1.[9] The various RPM CONE studies performed for PJM have typically estimated that CONE Area 1 has the highest labor costs in PJM, and Stantec's estimates follow that pattern. The IMM provided PJM with Stantec's construction labor cost estimates for the other CONE Areas, and those ranged from approximately $20 million to approximately $29 million for 2018.

18. For a CC plant built in CONE Area 1, Stantec estimated 1.3 million hours of construction labor at an average labor rate of $88/hour[10], for a labor construction cost of $ 117.2 million in 2013 dollars, and escalated its estimate to $140.9 million for a 2018 in-service date. The IMM did not provide PJM with construction labor cost estimates for a CC plant in the other PJM CONE Areas.

19. As I showed in my September 25, 2014 affidavit in Docket No. ER14-2940-000, , the Pasteris/Stantec labor construction cost estimate for CT plants closely track publicly available data on utility system construction wages from the United States Bureau of Labor Statistics ("BLS") Quarterly Census of Employment and Wages ("CEW"), when adjusted for inflation, fringe benefits and labor productivity factors. As I also showed in that affidavit, the Pasteris/Stantec labor cost estimates for a CT in CONE Area 1 are consistent with the CONE Area 1 CT plant labor hours and labor costs estimated in the 2011 triennial review CONE study prepared by CH2M Hill for PJM.[11] In their study, CH2M Hill estimated 361,088 man hours of construction labor (compared to Stantec's estimate of 360,000 hours) at a rate of $84.66/hour (compared to Stantec's estimate of $86.00/hour) and total construction labor costs of $30.57 million in 2011 dollars.[12] To get

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7 *Id*. at 2.

8 *Id.* at 7. The labor rate includes fringe benefits.

9 *Id.* at 7.

10 The labor rate includes fringe benefits.

11 *See* Kathleen Spees, et al., Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, the Brattle Group, Appendix A (August 24, 2011), http://pjm.com/~/media/committees-groups/committees/mrc/20110818/20110818-brattle-report-on-cost-of-new-entry-estimates-for-ct-and-cc-plants-in-pjm.ashx.

12 *Id.* at Appendix Page A-33.

an estimate of what the CH2M Hill construction labor cost would be in 2018 dollars, I inflated their 2011 estimate by the expected rate of inflation as derived by the difference between 20 Year Treasury Bonds and 20 Year Treasury Inflation Protected Bonds from 2004 to the present, which is 2.39 percent per year.[13] This would give an adjusted CH2M Hill construction labor estimate of $36.06 million in 2018 dollars for a CT in CONE Area 1, or just $1.2 million below the Pasteris/Stantec labor cost estimate for a CT plant brought in service in CONE Area 1 in 2018.

20. I will not repeat the CT analysis in detail here. PJM has shown that the CT CONE values, including the construction labor cost estimates, are reasonable in Docket No. ER14-2940-000. The same CT CONE values, based on the same construction labor cost estimates, are proposed here for use in connection with MOPR. I am advised by counsel that PJM will accept the CT CONE values approved in that proceeding for the VRR Curve for use with MOPR as well, to ensure consistency between those values.

21. The CC CONE values proposed here for MOPR, including the alternative construction labor cost estimates, also are reasonable. As noted above, for a CC plant built in CONE Area 1, Stantec estimated 1.3 million hours of construction labor at an average labor rate of $88/hour.[14] Stantec's labor hour estimate is the same as the Sargent & Lundy labor hour estimate for the CC plant in CONE Area 1, and I therefore adopted that value for the CC construction labor for all CONE Areas. It is reasonable to use the same number of construction labor hours in each CONE Area because the scope of the "inside-the-fence" construction is essentially the same for all CONE Areas.

22. For the CC plant hourly wage rates, however, I was required to go beyond the Stantec/Pasteris estimates, although those estimates served as a valuable benchmark. As noted, the IMM provided CC labor estimates only for CONE Area 1, but MOPR requires CC CONE estimates for all CONE Areas. For consistency across all CONE Areas, I used a single methodology to estimate the hourly wage rates, based on public data on utility system construction wages and information from the various RPM CONE studies. My primary source of information was the construction labor cost reports publicly available from the BLS CEW for Utility Construction Wages[15] for different states corresponding to the respective CONE Areas.[16] BLS reports these wages on a workweek basis; I divided the weekly amounts by 40 hours to derive an hourly rate.

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13 Federal Reserve Economic Database ("FRED") at http://research.stlouisfed.org/fred2/ and selecting data to graph and download at http://research.stlouisfed.org/fred2/graph/?id=DGS20,DFII20,# on September 23, 2014.

14 The labor rate is stated in 2013 dollars and includes fringe benefits.

15 This specific wage index is identified in the BLS CEW reports as North American Industrial Classification Standard ("NAICS") 2371.

16 United States Bureau of Labor Statistics (BLS) Quarterly Census of Employment and Wages (CEW) available at http://www.bls.gov/cew/#databases. For CONE Area 1 New Jersey Statewide labor rates were used (Series Id. ENU340004052371). For CONE Area 2, Maryland Statewide labor rates were

23. I also made an adjustment to the BLS wage numbers in recognition of the slightly higher average labor costs that Stantec, CH2M Hill, and Sargent & Lundy all estimated for a CC plant. The average rate from CH2M Hill for a CC was about 1% higher than that for a CT; Stantec's was about 2.3% higher, and Sargent & Lundy's was about 5.2% higher. I chose a factor about half-way between the Stantec and Sargent & Lundy percentage differences, i.e., 3.7%, and multiplied that factor by the BLS hourly wage rates to approximate the slightly higher average labor costs for a CC. I then escalated the BLS average wages to reflect the timing differences. The last full year for which the BLS CEW has published utility construction labor rates is 2013. To escalate these values to 2018 dollars I used an inflation rate of 2.32 percent per year, which is the implied inflation rate since the beginning of 2012 based on the average difference in interest rates between the 20 Year Treasury Bond Constant Maturity and the 20 Year Treasury Inflation Protected Bond Constant Maturity over that period.[17]

24. The BLS average wages also need to be adjusted to reflect fringe benefits. Actual wages paid to labor constitute only approximately one-half of the total cost of labor. Employers also are responsible for other labor related costs such as taxes, benefits, and workers' compensation. This "fringe" must be added to the basic wage rate to obtain the total labor cost. From CH2M Hill's 2011 work, the implied fringe was 1.03 times the wage rate.[18] Discussions with Sargent & Lundy indicated a range of fringe from 0.92 times the wage rate to 1.04 times the wage rate.

25. Next, standard practice in estimating construction labor costs is to measure "labor productivity" by region relative to a benchmark area, usually the Gulf Coast of the United States which is assigned by cost estimators a productivity factor of 1. Labor productivity greater than 1 usually accounts for items such as regional practices that could increase the effective labor cost either through labor rates or labor hours required. Derivation of labor productivity factors is a judgment based on experience. Discussions with Sargent & Lundy indicate a range of productivity factors between 1.13 and 1.19. These values are consistent with labor productivity factors used by CH2M Hill in the previous CONE Study for Cone Areas 1, 3, and 4, but also higher than those assumed by CH2M Hill for

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used (Series Id. ENU240004052371). For CONE Area 3, Ohio Statewide labor rates were used (Series Id. ENU390004052371). For CONE Area 4, Pennsylvania Statewide labor rates were used (Series Id. ENU420004052371). For CONE Area 5, Virginia Statewide labor rates were used (Series Id. ENU510004052371).

17 Federal Reserve Economic Database ("FRED") at http://research.stlouisfed.org/fred2/ and selecting data to graph and download at http://research.stlouisfed.org/fred2/graph/?id=DGS20,DFII20,# on September 23, 2014.

18 Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, Appendix A.4, page A-33. The implied fringe was computed based on the New Jersey Utility Construction Wage Rate for 2011, inflated to 2015 dollars and then dividing the hourly rate of $84.66 by wage rate and subtracting 1.

Cone Areas 2 and 5 where productivity was assumed to be 1.[19] For the purposes of the MOPR screen value for the CC technology I have elected to use a productivity factor of 1.19 (i.e., the highest of the Sargent & Lundy values) as a conservative approach to ensure the MOPR screening value does not assume more productive labor than may be the case for individual projects. Developers with more productive labor than this default assumption can make such a showing as necessary in the unit-specific review process.

26. Table 1 below shows the results of applying the steps outlined in paragraphs 22, 23, and 24 to determine the construction labor costs for the CONE Areas. Referring to that table, the 2013 wage rate is the BLS weekly wage value, divided by 40 and increased by 3.7% to better approximate the slightly higher CC costs. The 2018 wage rate shows the result of escalating the 2013 values to 2018 using the inflation rate since 2012, as discussed above. The fourth and fifth rows of the Table show the result of adding a low and high estimate of fringe benefits to the basic hourly wage. The fifth and sixth rows show high and low labor cost estimates after applying the productivity factor of 1.19 and multiplying the full loaded, 2018, productivity-adjusted average hourly rate by 1.3 million hours.

Table 1: Deriving CC Construction Labor Values from IMM and BLS Data

	CONE Area 1 (EMAAC)	**CONE Area 2 (SWMAAC)**	**CONE Area 3 (RTO)**	**CONE Area 4 (WMAAC)**	**CONE Area 5 (Dominion)**
State	New Jersey	Maryland	Ohio	Pennsylvania	Virginia
Wage Rate (2013 $/hr)	$44.79	$28.28	$33.80	$38.31	$26.44
Wage Rate (2018 $/hr)	$50.26	$31.73	$37.93	$42.99	$29.67
Low Fringe(0.92)	$96.49	$60.92	$72.32	$82.53	$56.96
High Fringe(1.04)	$102.52	$64.73	$77.37	$87.69	$59.33
Total Construction Labor Costs ($millions 2018 dollars)					
Low-Fringe Estimate	$149.3	$94.2	$112.6	$127.7	$88.1
High-Fringe Estimate	$158.6	$100.1	$119.7	$135.7	$91.8

27. I note that the construction labor costs in Table 1 are quite close to those derived by CH2M Hill for PJM during the 2011 CONE Review when adjusting for the differences in labor hours.[20]

19 *Id.* at Appendix A, page A-9.

20 *Id.* at Appendix B.4, B-37, B38. CH2M Hill estimated 1.15 million labor hours at an hourly rate of $85.16 and making other adjustments such as for productivity, the total labor cost in 2018 dollars would be approximately $137 million for EMAAC with fewer labor hours. If the labor hours were the same as estimated by

28. In Table 2 below, I present the final construction labor cost estimates for both CC and CT plants for each CONE Area. The CT values are the same as those described in my affidavit in Docket No. ER14-2940-000. The CC values are the averages of the low-fringe and high-fringe estimates shown in the last two rows of Table 1, with one adjustment. The adjustment to each of the CC estimates (which was also made to each of the CT estimates) is to ensure that the PJM derived estimate does not omit labor costs associated with the installation of dual-fuel capability. As explained in my affidavit in Docket No. ER14-2940-000, Sargent & Lundy included dual-fuel labor in its overall construction labor estimate, while Pasteris/Stantec had the dual-fuel labor in a separate dual-fuel line item. To ensure that labor cost is not lost when the Pasteris/Stantec labor estimate replaces the Sargent & Lundy labor estimate, the construction labor cost for dual-fuel capability (about $1 million) must be added back. In looking at Table 2, it is important to note that the large difference in labor costs between the CT and CC is primarily due to labor hours being approximately 4 to 5.5 times higher for the CC compared to the CT, which is to be expected given the complexity of constructing a CC plant compared to a simple cycle CT plant.

Table 1: IMM Presented/PJM Derived and Adopted Construction Labor Values ($ millions 2018 dollars)

	CONE Area 1 (EMAAC)	CONE Area 2 (SWMAAC)	CONE Area 3 (RTO)	CONE Area 4 (WMAAC)	CONE Area 5 (Dominion)
IMM CT	$38.3	$22.9	$21.4	$30.5	$21.1
PJM Derived CC	$153.9	$97.2	$116.2	$131.7	$89.9

C. Use of Bureau of Labor Statistics (BLS) Indices to Adjust Gross CONE between Comprehensive Periodic Reviews.

29. PJM's MOPR tariff provision states that PJM will adjust the gross CONE values that are used to set the MOPR offer screening price "in the same manner" as the index adjustment specified in the tariff for the CONE values that are used to determine the VRR Curve.[21] PJM is proposing to maintain a common approach to adjusting the CONE values in both the MOPR and the VRR Curve. However, because PJM is proposing in Docket No. ER14-2940-000 to change the index adjustment methodology for the VRR Curve, the cross-reference in the MOPR tariff language will now apply that new index adjustment methodology to the MOPR gross CONE values as well. In this part of my affidavit, I explain that new index adjustment approach and why it is reasonable for the MOPR CONE values. I also explain and support one difference between the approach for CT plants and CC plants. The new index is a composite of three indices that track the major cost components of a new plant, weighted based on the relative contribution of those cost inputs to the cost of the plant. Those contributions differ between a CT and CC plant, and so the weightings must differ also. In Docket No. ER14-2940-000, PJM

S&L and the IMM/Pasteris, the cost in 2018 dollars would be about $155 million for EMAAC.

21 PJM Tariff, Attachment DD, section 5.14(h).

proposes to state in the tariff those weighting percentages for the CT CONE from which the VRR Curve is determined. Those weightings will also apply to the CT CONE used in MOPR, but different weightings must be specified for the CC CONE used in MOPR to screen offers from CC plants.

30. As discussed in my affidavit in Docket No. ER14-2940-000 PJM currently uses Handy-Whitman's "Total Other Production Plant" index for the appropriate location to update its Gross CONE values annually. There are several concerns relating to the continued use of this index. The Handy-Whitman index:

- is not specifically tailored to the construction of CTs or CCs;
- has escalated more quickly than the rate of cost increases found through CONE studies, and for costs associated with labor, materials, and turbine generator sets;
- is not transparent in its methodologies;
- is updated only twice each year;
- is available only through subscription and thus it is not publically available; and
- although it publishes a Total Production Plant index, it does not track well with other measures of cost inflation or match the changes in the Gross CONE that have been observed in PJM's three periodic CONE reviews.

From a market transparency perspective, an index that can be verified by market participants and monitored month by month can help anticipate yearly changes to the MOPR CONE values. That more accurate reflection of actual changes in the MOPR CONE values over time should enhance the efficiency and cost-effectiveness of the MOPR offer-screening process and unit specific review process for PJM, the IMM and generation developers.

31. In place of the Handy-Whitman index, PJM has proposed to use a composite index comprised of three BLS indices relevant to three major cost categories associated with turbine power plant construction, i.e., utility system construction wages, construction materials, and turbines. Specifically, as explained in my affidavit in Docket No. ER14-2940-000, the composite index will be comprised of the following three indices:

- Materials: Producer Price Index ("PPI") - Commodities; Stage of Processing, Materials and components for construction;[22]
- Turbine: PPI Index- Commodities; Turbines and turbine generator sets;[23] and

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[22] PPI Index- Commodities; Stage of Processing, Materials and components for construction | Series ID: WPUSOP2200 *http://data.bls.gov/timeseries/WPUSOP2200.*

[23] PPI Index- Commodities; Turbine and Turbine generator sets | Series ID: WPU1197 *http://data.bls.gov/timeseries/WPU1197?include_graphs=false&output_type=column&years_option=all_years.*

- Wages: Quarterly Census of Employment and Wages; (Corresponding to the applicable location), Utility system construction, Average annual pay.[24]

Figure 1 below shows the breakdown by specific cost category of the various line items sorted by Sargent & Lundy into the categories of turbine, materials, and labor costs and are the same as used for the Reference Resource CT.

Figure 1: Categorization of Costs as Turbine, Materials, and Labor

Line Items from S&L	Cost Category
Gas Turbines	Turbine
HRSG / SCR	Material
(OFE) Sales Tax	Material
"Equipment Subtotal" *	Material
Construction Labor	Labor
Other Labor	Labor
Materials	Material
(EFC) Sales Tax	Material
EPC Contractor Fee	Material
EPC Contingency	Material
Project Development	Labor
Mobilization and Start-Up	Labor
Net Start-Up Fuel Costs	Material
Electrical Interconnection	Material
Gas Interconnection	Material
Land	Material
Fuel Inventories	Material
Non-Fuel Inventories	Material
Owner's Contingency	Material
Financing Fees	Material

* "Equipment Subtotal" includes the condenser, steam turbine and other equipment for the CC; for CT, it includes just the "Other Equipment"

32. In Docket No. ER14-2940-000, PJM proposed to weight these indices 20% wages, 50% materials, and 30% turbines, in order to derive a composite index for adjusting the CT plant CONE for the VRR Curve. That same weighting will be applied to adjust the CT plant CONE used in MOPR. These weightings were derived by assigning each major cost component of the CT CONE estimate to one of these categories (per Figure 1 below), calculating the resulting relative proportions of each of

24 *See supra* note 16.

the three categories, and rounding the values to arrive at a single set of approximate proportions to state in the tariff for all CONE Areas and all future Delivery Years.

33. However, the percentages attributable to turbines, material, and labor for the CC CONE needed for MOPR will necessarily be different than the weightings for the CT. Therefore, applying the same method I used for the CT weightings (as described in the previous paragraph), I derived weightings to use for a composite index for the CC CONE. The assignment of cost components among the three major categories is the same for the CC as it was for the CT, i.e., the mapping shown in Figure 1. I then calculated the relative contribution of each of these three cost categories to the CC CONE. As would be expected from the greater scope and complexity of constructing a CC plant, the turbine costs comprise a smaller share of the total project cost (compared to a CT) while the other materials (including the heat steam recovery generator—not typically present in a simple-cycle CT) comprise a much larger share. Equally unsurprising, the labor costs needed to build a more complex plant make up a larger share of the CC cost than they do of the CT cost.

34. Table 3 provides the resulting approximate percentage weighting of turbine, material and labor costs to be used for the purposes of adjusting the MOPR screen CC CONE each year corresponding to the contribution to the CC CONE, and the state from which the labor costs will be drawn by CONE Area. The states used for labor in the CONE Area are the same as discussed in my affidavit in Docket No. ER14-2940-000 validating the IMM construction labor costs adopted by PJM for the Reference Resource CT.

Table 3: Percentage of Cost for CONE

	CONE Area 1 (EMAAC)	**CONE Area 2 (SWMAAC)**	**CONE Area 3 (RTO)**	**CONE Area 4 (WMAAC)**	**CONE Area 5 (Dominion)**
State: Labor	New Jersey	Maryland	Ohio	Pennsylvania	Virginia
Labor	25%	25%	25%	25%	25%
Materials	60%	60%	60%	60%	60%
Turbines	15%	15%	15%	15%	15%

This concludes my affidavit.

Attachment D

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER15-**68-000

AFFIDAVIT OF DR. SAMUEL A. NEWELL ON BEHALF OF PJM INTERCONNECTION, L.L.C.

My name is Dr. Samuel A. Newell, and I am a Principal with *The Brattle Group* ("Brattle"). I am submitting this affidavit in support of the proposal by PJM Interconnection, L.L.C. ("PJM") to update the administrative estimates of the costs to construct a new combustion turbine ("CT") power plant and a new combined cycle ("CC") power plant, used to determine minimum offer screening parameters in the Minimum Offer Price Rule under PJM's capacity market (known as the Reliability Pricing Model or "RPM").

I have extensive experience estimating new entry costs in capacity markets administered by Regional Transmission Organizations ("RTOs") and have submitted expert testimony on that subject in several Commission proceedings. I submitted testimony (jointly with Mr. Christopher Ungate of Sargent & Lundy, LLC ("S&L")) for ISO-New England, Inc. ("ISO-NE") in April 2014 regarding the cost of new entry ("CONE") for the ISO-NE Forward Capacity Market demand curve.[1] In December 2013, I also sponsored testimony (again with Mr. Ungate) to establish the ISO-NE Offer Review Trigger Prices based on estimates of Net CONE values for various technologies.[2] I co-authored the 2011 PJM CONE study[3] and provided affidavits in ensuing litigation,[4]

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1 Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, Testimony of *Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve*, April 1, 2014.

2 Before the Federal Energy Regulatory Commission Docket No. ER14-616-000, *Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England* and the accompanying "2013 Offer Review Trigger Prices Study," December 11, 2013.

Before the Federal Energy Regulatory Commission, Docket No. ER14-616-000, *Affidavit of Christopher D. Ungate on Behalf of ISO New England*, December 11, 2013.

3 Kathleen Spees, Samuel Newell, Robert Carlton, Bin Zhou, and Johannes Pfeifenberger, *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, August 24, 2011 ("2011 PJM CONE Study"), Available at http://www.pjm.com/documents/reports.aspx.

which informed the Net CONE values PJM used in its capacity auctions for the 2016/2017 and 2017/2018 delivery years. In addition, my extensive related experience in market design for resource adequacy for ISO-NE, PJM, the New York Independent System Operator, Inc., the Midcontinent Independent System Operator, Inc., and the Electric Reliability Council of Texas has provided broad perspective on the capacity market context in which CONE is used.

My experience working for RTOs is also informed by my work for market participants building, buying, and contracting with generation plants. In that connection, I have led numerous generation asset valuation studies and resource planning studies.

I am an economist and engineer with more than 16 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. Prior to joining The Brattle Group, I was the Director of the Transmission Service at Cambridge Energy Research Associates and, before that, a Manager in the Utilities Practice at A.T.Kearney. I earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

Complete details of my qualifications, publications, reports, and prior experience are set forth in my resume which is attached to my affidavit.

In October of 2013, PJM retained Brattle to review the Cost of New Entry ("CONE") parameters of the RPM, as required periodically under PJM's tariff. I led the Brattle review of CONE parameters, together with Mr. Ungate and his team at S&L as a sub-contractor. The Brattle team's role was to estimate CONE, starting by determining the configurations and locations of the reference plants, overseeing S&L estimates of the capital cost and fixed operation and maintenance ("O&M") costs, estimating certain components of capital costs (*e.g.*, gas and electric interconnection and land costs), estimating certain components of fixed O&M costs (*e.g.*, property taxes and firm gas contracts), analyzing the key financial assumptions (*e.g.*, cost of capital), and calculating the levelized costs. S&L's role was to contribute expertise in determining the configurations and locations of the reference plants and to provide detailed capital and fixed O&M cost estimates of the reference plants specified for each PJM CONE Area.

The results of the analysis completed by Brattle and S&L are set forth in a report entitled "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM with June 1, 2018 Online Date" ("2014 CONE Study"). A copy of the 2014 CONE Study, which was prepared under my direction and supervision, is attached to my affidavit.

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[4] Before the Federal Energy Regulatory Commission, Docket No. ER12-513-000, *Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, supporting PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's Reliability Pricing Model*, November 21, 2012.

On September 25, 2014, I submitted with Mr. Ungate an affidavit on behalf of PJM in Docket No. ER14-2940-000 to support the CT CONE values (based primarily on the 2014 CONE Study) that PJM filed in that proceeding for use in the RPM Variable Resource Requirement ("VRR") Curve. In this proceeding, PJM is filing changes to the CT and CC new entry cost estimates used in the MOPR, again based largely on the 2014 CONE Study. The CT values presented here are the same CT values PJM filed in Docket No. ER14-2940-000 for the VRR Curve, and the CC values, like the CT values, also were calculated from the 2014 CONE Study and reflect certain changes requested by PJM. This affidavit summarizes the methodology and results of the 2014 CONE Study, and notes the elements of the estimates changed at PJM's request.

Our starting point was to determine representative technical specifications and locations for the reference natural gas-fired CT and CC plants. To do so, we relied primarily on the "revealed preference" of developers in the PJM region and around the U.S., as reflected by recent and proposed CC and CT plants. For CONE Areas where revealed preference data is weak or scattered, we identified promising locations from a developer perspective based on proximity to gas and electric interconnections and key economic factors such as labor rates and energy prices.

For CTs, we defined a representative reference plant based on two General Electric Frame 7FA.05 gas turbines with selective catalytic reduction ("SCR") technology and carbon monoxide ("CO") catalyst environmental controls to reduce air pollutant emissions, evaporative cooling for power augmentation, and dual-fuel capability. We found in our analysis that dual fuel has not been dominant in the CONE Area 3: Rest of RTO area for CT plants, but PJM requested that we calculate CONE in all areas assuming dual-fuel capability. The net summer installed capacity of such a plant is 383 to 396 MW depending on the ambient atmospheric conditions assumed in each location, with a net heat rate of approximately 10,300 Btu/kWh.

For CCs, we defined a representative reference plant based on a 2x1 plant configuration with two General Electric Frame 7FA.05 gas turbines, SCR technology and CO catalyst environmental controls to reduce air pollutant emissions, evaporative cooling for power augmentation, and dual fuel capability in each CONE Area except CONE Area 3: Rest of RTO and CONE Area 2: SWMAAC. In place of dual-fuel capability in SWMAAC, we assumed the reference CC plant will contract for firm transportation service on the Dominion Cove Pipeline ("DCP"). The net summer installed capacity of such a plant is 649 to 668 MW when operating the supplemental duct firing capacity depending on the ambient atmospheric conditions assumed in each location, with a net heat rate of approximately 7,000 Btu/kWh in duct firing mode.

Based on these configurations, we estimated the capital and fixed O&M costs of the reference CC and CT plants for each CONE Area. More specifically, for each plant specified, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction ("EPC") costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimated annual fixed operating and maintenance (O&M)

costs, including labor, materials, property taxes, and insurance. The 2014 CONE Study describes the bases for each of these estimates.

We then calculated the levelized CONE value for the reference CT and CC plants using an after-tax weighted average cost of capital ("ATWACC") of 8.0% based on our review of various market reference points, as documented in the 2014 CONE study. We calculated levelized costs assuming 20 years of cash flows that are constant in real terms (*i.e.*, growing with inflation) and, alternatively, cash flows that are constant in nominal terms. Because PJM is filing CONE values based on the level-nominal assumption, I present only those results in this affidavit.

Following the release of the 2014 CONE Study, PJM conducted a stakeholder process to review the report and solicit input on the assumptions. As a result of those discussions, PJM chose to adopt, in lieu of the labor cost estimates provided in the 2014 CONE Study, an alternative labor cost estimate provided by the Independent Market Monitor for the PJM Region.[5] At PJM's request, we included these alternative labor costs in a recalculation of the CONE values from the 2014 CONE Study, and show those results in this affidavit.

The estimated CONE for the reference CT plant in each CONE Area with an online date of June 1, 2018 based on the 2014 CONE Study, including the level-nominal assumption and dual-fuel capability for all areas, as calculated as an alternative option in the 2014 CONE Study, plus the alternative labor cost estimate provided by PJM are as shown in Table 1.

Table 1
Reference CT Plant CONE Estimates

CONE Area	**CT CONE** *($/MW-year)*
CONE Area 1	$132,200
CONE Area 2	$130,300
CONE Area 3	$128,900
CONE Area 4	$130,300
CONE Area 5	$126,400

The estimated CONE for the reference CC plant in each CONE Area with an online date of June 1, 2018 based on the 2014 CONE Study, including the level-nominal assumption, as calculated as an alternative in that study, plus the alternative labor cost estimate provided by PJM, are as shown in Table 2.

5 *See* Affidavit of Dr. Paul Sotkiewicz of PJM, which is being submitted concurrently with this affidavit

Table 2
Reference CC Plant CONE Estimates

CONE Area	**CC CONE** *($/MW-year)*
CONE Area 1	$185,700
CONE Area 2	$176,000
CONE Area 3	$172,600
CONE Area 4	$179,400
CONE Area 5	$164,200

This concludes my affidavit.

SAMUEL A. NEWELL

Principal

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Dr. Samuel Newell's expertise is in the analysis and modeling of electricity markets, the transmission system, and RTO rules. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation and development, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC and has testified before the American Arbitration Association.

Dr. Newell earned a Ph.D. in technology management and policy from the Massachusetts Institute of Technology, an M.S. in materials science and engineering from Stanford University, and a B.A. in chemistry and physics from Harvard College.

AREAS OF EXPERTISE

- Electricity Wholesale Market Design
- Valuation of Generation Assets
- Energy Litigation
- Integrated Resource Planning
- Evaluation of Demand Response (DR)
- Transmission Planning and Modeling
- RTO Participation and Configuration
- Analysis of Market Power
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Electricity Market Wholesale Design

- **Third Triennial Review of PJM Capacity Market and CONE Study**. For PJM, conducted third tri-annual review of the Reliability Pricing Model. Addressed the shape of the demand curve, the Cost of New Entry (CONE) parameter, and the methodology for estimating the energy margins and ancillary services revenues in the Net CONE calculation.
- **ISO New England Capacity Demand Curve.** For ISO New England, worked with RTO staff and stakeholders to develop a selection of capacity demand curves and evaluate them for their efficiency and reliability performance. Began with a review of lessons learned from other market and an assessment of different potential design objectives. Developed and implemented a statistical simulation model to evaluate probabilistic reliability, price, and reserve margin outcomes in a locational capacity market context under different candidate demand curve shapes. Also worked with

Sargent & Lundy and stakeholders to develop estimates for the Net Cost of New Entry (Net CONE) to which the prices in the demand curve are indexed. Submitted testimonies before FERC, with ongoing support to develop locational demand curves for individual capacity zones.

- **Market Development Vision**. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **Economically Optimal Reserve Margins**. For the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.
- **Offer Review Trigger Prices in ISO-NE**. For the Internal Market Monitor in ISO New England, developed offer review trigger prices for screening for uncompetitively low offers in the Forward Capacity Market. Collaborated with Sargent & Lundy to conduct a bottom-up analysis of the costs of building and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency, and demand response. For each technology, estimated the capacity payment needed to make the resource economically viable, given expected non-capacity revenues, a long-term market view, and a cost of capital. Recommendations were filed with and accepted by the Federal Energy Regulatory Commission (FERC).
- **Evaluation of Investment Incentives and Resource Adequacy in ERCOT**. For the Electric Reliability Council of Texas (ERCOT), led a team that (1) characterized the factors influencing generation investment decisions; (2) evaluated the energy market's ability to support investment and resource adequacy at the target level; and (3) evaluated options to enhance long-term resource adequacy while maintaining market efficiency. Conducted the study by performing forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed

a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Findings and recommendations became a launching point for a PUCT Proceeding, in which I filed comments and presented at several workshops between June 2012 and July 2013.

- **Second Triennial Review of PJM Capacity Market and CONE Study**. For PJM, conducted second tri-annual review of the Reliability Pricing Model. Analyzed capacity auction results and response to market fundamentals. Interviewed stakeholders and documented concerns. Addressed key market design elements and recommended improvements to reduce pricing uncertainty and safeguard future performance. Led a study of the Cost of New Entry (CONE), based on detailed engineering estimates developed by EPC contractor CH2M HILL, for use in PJM's setting of auction parameters. Served as PJM's witness in filing CONE values and a Settlement Agreement.
- **Evaluation of Reliability Pricing Model (RPM) Results and Design Elements**. For PJM, co-led a detailed review of the performance of its forward capacity market. Reviewed the results of the first five forward auctions for capacity. Concluded that the auctions were working and demonstrated success in attracting and retaining capacity, but made more than thirty design recommendations. Recommendations addressed ways to remove barriers to participation, ensuring adequate compensation/penalties, and improving the efficiency of the market. Resulting whitepaper was submitted to the FERC and presented to PJM stakeholders.
- **Evaluation of ISO-NE Forward Capacity Market (FCM) Results and Design Elements.** With the ISO-NE market monitoring unit, reviewed the performance of the first two forward auctions in ISO-NE's FCM. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor. Resulting whitepaper filed with the FERC and presented to ISO-NE stakeholders.
- **Evaluation of a Potential Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its existing short-term ICAP market structure with a proposed four-year forward capacity market (FCM) design. Evaluation based on stakeholder interviews, the experience of PJM and ISO-NE with their forward capacity markets, and review of the economic literature regarding forward capacity markets. Addressed the following attributes of FCM relative to the existing market: risks to buyers and suppliers, mitigation of market power, implementation costs, and long-run costs. Recommendations used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.

- **RTO Accommodation of Demand Response (DR) for Resource Adequacy**. For MISO, helped modify its tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying in detail the practices of other RTOs, and by characterizing the DR resources within the MISO footprint.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- **Integration of DR into MISO's Energy Markets**. For MISO, wrote a whitepaper evaluating the available approaches to incorporating economic DR in energy markets. Assessed the efficiency and the "realistic achievable potential" for each approach. Identified implementation barriers at the state and RTO levels. Recommended changes to business rules to efficiently accommodate curtailment service providers (CSPs).
- **MISO Capacity Market Enhancements**. Supported MISO in developing market design elements for its proposed annual locational capacity auctions.
- **Evaluation of MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its new resource adequacy construct. Identified several major successes and a series of recommendations for improvement in the areas of load forecasting, locational resource adequacy, and determination of the target level of reliability. The report incorporates extensive stakeholder input and review, and comparisons to other ISOs' capacity market designs. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements.
- **Evaluation of MISO's Demand Response Integration**. For MISO, conducted an independent assessment of its progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers to date. Assessed the likelihood of MISO's "ARC Proposal" to eliminate barriers to participation by curtailment service providers. Made recommendations for potential further improvements to market design elements.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, allowing reductions in installed capacity margins) on capacity costs, emergency procurement costs, capacity prices, and energy prices. Resulting whitepaper submitted by ISO-NE to the FERC in its filing on tie-benefits.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Also developed guidelines on the kinds of information ISO-NE should provide for major initiatives.

- **LMP Impacts on Contracts**. For a West Coast client, critically reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated potential incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.
- **RTO Accommodation of Retail Access**. For MISO, made recommendations for improving business practices in order to facilitate retail access (and to enable auctions for the supply of regulated generation service). Analyzed the retail access programs in the three restructured states within MISO -- Illinois, Michigan, and Ohio. Performed a detailed study of retail accommodation practices in other RTOs, focusing on how they have modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

Valuation of Generation Assets and Contracts

- **Valuation Methodology for a Coal Plant Transaction in PJM**. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.
- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Analysis focused on projected market revenues, operating costs, and capital investments likely needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.

- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM**. For a major retail energy provider preparing to bid for a bundle of generation assets, provided energy and capacity price forecasts and reviewed their valuation methodology. Analyzed the supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the Dayzer model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer proposing to build a several hundred megawatt wind farm in Michigan provided a market-based revenue forecast for energy and capacity. Identified gas and CO_2 allowance prices as the key drivers of revenue uncertainty, and evaluated the implications of several detailed scenarios around these variables.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant**. For the owner of a large cogeneration plant in PJM, conducted an analysis of revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation**. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of plausible scenarios. Identified key uncertainties and risks in the acquisition of such assets.

Energy Litigation

- **Demand Response Arbitration**. Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony in arbitration before the American Arbitration Association (non-public).

- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.
- **Contract Damages**. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Contract Termination Payment**. For an independent power producer, supported expert testimony on damages resulting from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's operating characteristics and costs. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

Integrated Resource Planning (IRP)

- **IRP in Connecticut (for the 2008, 2009, 2010, 2012, and 2014 Plans)**. For the two major utilities in Connecticut and The Connecticut Department of Energy and Environmental Protection (DEEP), lead the analysis for five successive integrated resource plans. Plans included projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, and REC markets, and suppliers' likely investment/retirement decisions. Addressed policy questions regarding supply risks, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.

- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Serve (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Evaluation of Demand Response (DR)

- **ERCOT DR Potential Study**. For ERCOT, estimated the market potential for DR by end-user segment, based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented results to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an Eastern ISO, analyzed the biggest, most cost-effective opportunities for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.

- **Evaluation of DR Compensation Options**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **Wholesale Market Impacts of Price Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.
- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.
- **Present Value of DR Investments**. For Pepco Holdings, Inc., analyzed the net present value of its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated the reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate the short-term energy market price impact and addressed the long-run equilibrium offsetting effects through several plausible supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Documented findings in a whitepaper submitted to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Transmission Planning and Modeling

- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- **Benefit-Cost Analysis of a Major Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects of the Project

on congestion, capacity markets, CO2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the congestion, production cost, and LMP impacts using the PROMOD model.

- **Analysis of Transmission Congestion and Benefits**. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.
- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.
- **Benefit-Cost Analysis of New Transmission in the Midwest**. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.
- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a "metric" indicating access and congestion-related benefits provided by its transmission investments and operations.
- **Analysis of Transmission Constraints and Solutions**. For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.

- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices in Connecticut and Long Island.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration**. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- **Model Evaluation**. Led an internal Brattle effort to evaluate commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and Henwood LMP. Performed intensive in-house testing of each model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability and ease to calibrate models with backcasts using actual RTO data.

RTO Participation and Configuration

- **Market Impacts of RTO Seams**. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across regional transmission organization (RTO) seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams**. For a Wisconsin utility in a complaint proceeding before the FERC, assisted expert witness providing testimony regarding (1) the inadequacy of MISO and PJM's current efforts to improve inter-RTO coordination, and (2) the large net economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO and PJM in energy prices and in shadow prices of reciprocal coordinated flow gates. Analyzed results of MISO and PJM's market simulation models.
- **RTO Participation**. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Analysis of Market Power

- **Buyer Market Power**. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate various proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- **Vertical Market Power**. Before the NYPSC, examined whether the merger between National Grid and KeySpan potentially created incentives to exercise vertical wholesale market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **Market Monitoring and Market Power Mitigation**. For the PJM Interconnection, assessed their market mitigation practices and co-authored a whitepaper "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets" (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).

Tariff and Rate Design

- **Wholesale Rates.** On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings**. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- **Evaluation of Cogeneration Venture**. For an unregulated division of a utility holding company, led the financial evaluation of a nascent venture to build and operate cogeneration facilities on customer sites. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing**. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with top executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Wrote RFPs and developed negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.
- **M&A Advisory**. For a European utility aiming to enter the U.S. markets and enhance their trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy**. For a large power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the potential value client could bring to each potential customer. Worked directly with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment**. For the unregulated division of an integrated utility, performed a market assessment of established and emerging DG technologies. Projected future market sizes across multiple market segments in the U.S. Concluded that DG presented little immediate threat to the client's traditional generation business, and that it presented few opportunities that the client was equipped to exploit.
- **Fuel Cells**. For a European fuel cell component manufacturer, acted as a technology and electricity advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY and REGULATORY FILINGS

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Dr. Samuel A. Newell on behalf of Tri-State Generation and Transmission Association, Inc.," regarding an Analysis of Complaining Parties' Responses to Tri-State Generation and Transmission Association, Inc., September 10, 2014.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on behalf of the Maine Office of the Public Advocate, regarding an Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. regarding a Forward Capacity Market Demand Curve," filed April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on behalf of ISO New England Inc. regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve," filed April 1, 2014.

Before the Federal Energy Regulatory Commission Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of ISO New England" and accompanying "2013 Offer Review Trigger Prices Study," December, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Texas Public Utility Commission, presented "ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates" on behalf of The Electric Reliability Council of Texas (ERCOT) at a workshop in Project 40000 Commission Proceeding to Ensure Resource Adequacy in Texas, June 27, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 23, 2013.

Before the Federal Energy Regulatory Commission, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, Docket No. ER13-535-000, December 28, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, supporting PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's Reliability Pricing Model, filed November 21, 2012.

Before the Texas Legislature Committee on State Affairs, presented oral testimony: "The Resource Adequacy Challenge in ERCOT" on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Resource Adequacy in ERCOT: 'Composite' Policy Options" and "Estimate of DR Potential in ERCOT" on behalf of ERCOT at a workshop in Project 40480 Commission Proceeding Regarding Policy Options on Resource Adequacy, October 25, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Review of Resource Adequacy Proposals" on behalf of ERCOT at workshop in Project 40480 Commission Proceeding Regarding Policy Options on Resource Adequacy, September 6, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'" at workshop in Project 40000 Commission Proceeding to Ensure Resource Adequacy in Texas, July 27, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed January 13, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

"Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

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"Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives," presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.

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"Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'," presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

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September 23, 2014

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2014 PJM Variable Resource Requirement Parameter Review

At PJM's direction and having successfully earned the bid to perform the work, The Brattle Group conducted a review of Variable Resource Requirement curve parameters. The review was completed in compliance with the Section 5.10a of the PJM Tariff, which requires a quadrennial review of the three key parameters in the Variable Resource Requirement curve: the shape of the VRR curve, the Cost of New Entry, and the Energy and Ancillary Services offset methodology.

Brattle's preliminary findings were shared with PJM stakeholders in an April 29 special meeting of the MRC and Brattle's final reports and recommendations to PJM are posted on pjm.com

PJM has reviewed Brattle's analysis and recommendations and subsequently, has developed preliminary PJM staff recommendations. These recommendations will be the basis for discussion by stakeholders in the Capacity Senior Task Force in which PJM will seek to achieve consensus on modifications to the shape of the VRR Curve, CONE and E&AS. PJM's preliminary recommendations are posted on pjm.com.

The deadline for stakeholder consensus on recommendations is August 31, 2014, with a FERC filing deadline of October 1, 2014.

Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM

With June 1, 2018 Online Date

PREPARED FOR

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This report was prepared for PJM Interconnection, L.L.C. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or Sargent & Lundy, or their clients.

The authors would like to thank PJM staff for their cooperation and responsiveness to our many questions and requests. We would also like to thank the PJM Independent Market Monitor for helpful discussions.

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Executive Summary

PJM Interconnection, L.L.C (PJM) retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review the Cost of New Entry (CONE) parameters and other elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff.[1] This report presents our estimates of the CONE parameters for consideration by PJM and stakeholders in advance of their upcoming capacity auctions. Our review of the other elements of RPM is presented separately, in a concurrently-released report, the "Third Triennial Review of PJM's Variable Resource Requirement Curve" ("2014 VRR Report").

CONE represents the first-year total net revenue (net of variable operating costs) a new generation resource would need in order to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. It is the starting point for estimating the *Net* Cost of New Entry (Net CONE). Net CONE is defined as the operating margins that a new resource would need to earn in the capacity market, after netting margins earned in markets for energy and ancillary services (E&AS).

Accurate estimates of CONE, E&AS, and ultimately Net CONE are critical to RPM meeting its objectives because they provide the benchmark prices that define the administratively-determined demand curve for capacity (*i.e.*, the variable resource requirements, or VRR, curves). Without accurate Net CONE estimates, the VRR curves cannot be expected to procure the target amounts of capacity needed to satisfy PJM's resource adequacy requirements. Net CONE values are also used to establish offer price screens for market mitigation purposes under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[2]

We developed CONE estimates for gas-fired simple-cycle combustion turbine (CT) and combined-cycle (CC) power plants in each of the five administrative CONE Areas, with an assumed online date of June 1, 2018. Our estimates are based on complete plant designs reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. For both the CT and CC plants, we specify two GE 7FA turbines, with the CC equipped with a single heat recovery steam generator and steam turbine ("2×1 configuration"), cooling towers, and supplemental duct-firing capacity. All plants have selective catalytic reduction (SCR) for controlling NO_x. Most have dual-fuel capability except in the Rest of RTO Area, where actual projects have generally not been designed with dual-fuel capability (however, we also provide an alternative estimate with dual fuel at PJM's request following the gas delivery challenges experienced this past winter). CCs in the Southwestern Mid-Atlantic Area Council (SWMAAC) Area are also assumed not to have dual-fuel capability, consistent with projects in development and an assumption that they pay for firm gas transportation service instead. There

1 PJM Interconnection, L.L.C. (2014). Open Access Transmission Tariff, effective date 1/31/2014, ("PJM 2014 OATT"), accessed 5/1/2014 from http://www.pjm.com/~/media/documents/agreements/tariff.ashx, Section 5.10 a.

2 PJM 2014 OATT, Section 5.14 h.

are no other major differences in plant specifications among regions, although plant capacities and heat rates vary regionally with elevation and with ambient summer conditions.

For each plant specified, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimated annual fixed operating and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. We then translated the estimated costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to earn its required return on and of capital, assuming an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant investor, which we estimated based on various reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.8% at a 7% cost of debt and a 60/40 debt-to-equity capital structure.

Table 1 shows the resulting CONE values for CT plants in each CONE Area. We present the CONE estimates on both a "level-real" basis (a lower year-one cost recovery amount, assuming future contributions to cost recovery increase with inflation) and on a "level-nominal" basis (a higher year-one cost recovery requirement, assuming future contributions to cost recovery do *not* increase with inflation). As discussed in our 2014 VRR Report, we recommend that PJM transition from level-nominal to level-real CONE values. However, the following paragraphs discuss CONE in level-nominal terms to facilitate comparison to current parameter values.

Our CONE estimates vary by CONE Area due to differences in plant configuration and performance assumptions, labor rates, property tax laws, and other locational differences in capital and fixed O&M costs. The Eastern Mid-Atlantic Area Council (EMAAC) and SWMAAC Areas have the highest CT CONE estimates at $150,000/MW-year and $148,400/MW-year, respectively. Their higher CONE values reflect significantly higher labor costs in EMAAC and high property taxes in SWMAAC that are based on all property, not just land and buildings. The Western Mid-Atlantic Area Council (WMAAC) and Dominion Areas have the next highest CONE values of $143,500/MW-year and $141,200/MW-year, respectively. The Rest of RTO Area has the lowest CONE value of $138,000/MW-year due to the assumed absence of dual-fuel capability (consistent with observed development efforts) and lower labor costs. Under PJM's alternative assumption that future entrants there will invest in dual-fuel capability, the CT CONE value increases to $147,500.

Table 1 also compares these CT CONE estimates to two reference points: PJM's current parameters for the 2017/18 capacity auction and Brattle's prior estimates for the 2015/16 delivery year from its 2011 PJM CONE Study.[3] To produce a meaningful comparison, we show these reference points escalated to 2018 at 3% per year. As shown, our estimates are similar to the Brattle 2015/16 values, except in SWMAAC and Dominion where updated property tax calculations and labor costs contribute to increasing the CONE values by 9% and 15%, respectively. Our estimates in those

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[3] Spees, Kathleen, Samuel Newell, Robert Carlton, Bin Zhou, and Johannes Pfeifenberger, (2011). *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, August 24, 2011, ("2011 PJM CONE Study"), available at http://www.pjm.com/documents/reports.aspx.

CONE Areas are closer to the PJM 2017/18 parameters (which are higher than the Brattle 2015/16 values largely because they were escalated from prior settlement values using a Handy-Whitman index that has risen significantly faster than actual plant costs, as noted in our 2014 VRR Report). In the other CONE Areas (EMAAC, Rest of RTO, and WMAAC), our estimates are lower than the 2017/18 parameters. Overall, our estimates are within -8% to +6% of PJM's current parameters, depending on the Area.

Table 1
Recommended CT CONE for 2018/19

		CONE Area				
		1 EMAAC	2 SWMAAC	3 RTO	4 WMAAC	5 Dominion
Gross Costs						
Overnight	*($m)*	$400	$373	$348	$372	$364
Installed	*($m)*	$420	$391	$364	$390	$382
First Year FOM	*($m/yr)*	$6	$10	$7	$5	$8
Net Summer ICAP	***(MW)***	**396**	**393**	**385**	**383**	**391**
Unitized Costs						
Overnight	*($/kW)*	$1,012	$948	$903	$971	$931
Installed	*($/kW)*	$1,061	$994	$947	$1,018	$977
Levelized FOM	*($/MW-yr)*	$15,000	$25,600	$18,800	$13,700	$19,600
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$127,300**	**$126,000**	**$117,100**	**$121,800**	**$119,900**
Level-Nominal	***($/MW-yr)***	**$150,000**	**$148,400**	**$138,000**	**$143,500**	**$141,200**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$161,600	$150,700	$148,000	$155,200	$132,400
Brattle 2015/16 Estimate*	*($/MW-yr)*	$145,700	$134,400	$134,200	$141,400	$120,600
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	($11,600)	($2,300)	($10,000)	($11,700)	$8,800
Brattle 2015/16 Estimate	*($/MW-yr)*	$4,300	$14,000	$3,800	$2,000	$20,600
PJM 2017/18 Parameter	*(%)*	-8%	-2%	-7%	-8%	6%
Brattle 2015/16 Estimate	*(%)*	3%	9%	3%	1%	15%

Sources and Notes:
Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Table 2 shows the recommended CONE estimates for CC plants in each CONE Area, with comparisons to prior CONE values. EMAAC has the highest CONE estimates at $203,900/MW-year due to labor costs that are higher than the rest of PJM. SWMAAC and WMAAC have the next highest CC CONE estimates at $197,200/MW-year and $190,900/MW-year, respectively. The CONE

Areas with the lowest values are Rest of RTO (due to the lack of dual fuel) at $188,100/MW-year, and Dominion (as it has the lowest labor costs) at $182,400/MW-year. Under PJM's alternative assumption that future entrants will invest in dual-fuel capability in the Rest of RTO Area, the CC CONE value there increases to $193,700.

Compared to the Brattle 2015/16 values, the current CC CONE estimates are higher across all CONE Areas due to higher estimated costs of EPC contingency, owner's project development costs, and plant O&M costs. While the EPC contract costs increased in all Areas, the SWMAAC and Dominion values increased more due to higher estimated labor costs than in the previous analysis, as we found the prevailing wages in those regions include both union and non-union labor, whereas the previous analysis assumed strictly non-union labor.

Table 2
Recommended CC CONE for 2018/19

		CONE Area				
		1 EMAAC	2 SWMAAC	3 RTO	4 WMAAC	5 Dominion
Gross Costs						
Overnight	*($m)*	$808	$707	$709	$737	$708
Installed	*($m)*	$885	$775	$777	$808	$776
First Year FOM	*($m/yr)*	$17	$30	$19	$15	$19
Net Summer ICAP	***(MW)***	**668**	**664**	**651**	**649**	**660**
Unitized Costs						
Overnight	*($/kW)*	$1,210	$1,065	$1,089	$1,137	$1,073
Installed	*($/kW)*	$1,326	$1,168	$1,193	$1,245	$1,176
Levelized FOM	*($/MW-yr)*	$26,000	$44,800	$29,500	$23,300	$28,300
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$173,100**	**$167,400**	**$159,700**	**$162,000**	**$154,800**
Level-Nominal	***($/MW-yr)***	**$203,900**	**$197,200**	**$188,100**	**$190,900**	**$182,400**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$199,900	$176,300	$192,900	$191,800	$170,100
Brattle 2015/16 Estimate*	*($/MW-yr)*	$183,700	$161,000	$177,100	$176,700	$157,000
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	$4,100	$20,900	($4,700)	($900)	$12,200
Brattle 2015/16 Estimate	*($/MW-yr)*	$20,300	$36,200	$11,100	$14,200	$25,400
PJM 2017/18 Parameter	*(%)*	2%	11%	-3%	0%	7%
Brattle 2015/16 Estimate	*(%)*	10%	18%	6%	7%	14%

Sources and Notes:
Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

The updated CC CONE values have increased over the prior estimates more than the CT CONE values have, leading to a higher cost premium for CCs of $41,000–54,000/MW-year compared to $27,000-43,000/MW-year in our prior study. The most significant driver for the greater CC CONE increase is the relative difference in plant O&M costs estimated by S&L compared to the previous analysis. Fixed O&M costs decreased for CTs (with a larger fraction treated as variable costs) but increased for CCs. This difference explains approximately two-thirds of the increase in the CC premium over CTs. The rest of the difference is explained by higher labor rates and contingency and project development factors than in the prior study, which add more dollars to the cost of the more capital-intensive CC than the CT. In the Dominion CONE Area, the addition of the SCR to the CT largely offsets these differences.

The Brattle authors and Sargent & Lundy (S&L) collaborated in completing the CONE analysis and preparing this study. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M, and major maintenance costs and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

I. Introduction

A. Background and Objective

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which Variable Resource Requirement (VRR) curves set the "demand." The VRR curves are determined administratively based on a design objective to procure sufficient capacity for maintaining resource adequacy in all locations while also mitigating price volatility and susceptibility to market power abuse. To procure sufficient capacity, the VRR curves' price-quantity combinations are established to be consistent with the assumption that, in a long-term economic equilibrium, new entrants will set average capacity market prices at the Net Cost of New Entry (Net CONE). Net CONE is the first-year capacity revenue a new generation resource would need (in combination with expected energy and ancillary services margins) to recover its capital and fixed costs, given reasonable expectations about future cost recovery under continued equilibrium conditions. Thus, the sloped demand curve is assigned a price equal to Net CONE at approximately the point where the quantity equals the desired average reserve margin.[4] VRR curve prices are higher at lower reserve margins and lower at higher reserve margins, but all price points on the curve are indexed to Net CONE.

Just prior to each three-year forward auction, PJM determines Net CONE values for each of five CONE Areas, which are used to establish VRR curves for the system and for all Locational Deliverability Areas (LDAs). PJM calculates Net CONE for a defined "reference resource" by subtracting its estimated one-year energy and ancillary services (E&AS) net revenues from its estimated Cost of New Entry (CONE). CONE values are determined through triennial CONE studies (or litigated settlements), with escalation rates applied to the subsequent two auctions.[5] PJM separately estimates net E&AS revenue offsets annually for setting the Net CONE in each auction.

PJM has traditionally estimated CONE and Net CONE based on a gas-fired simple-cycle combustion turbine (CT) as the reference technology. However, as we explain in the concurrently-released 2014 VRR Report, we recommend defining the VRR curve based on the average Net CONE of a CT and a gas-fired combined-cycle gas turbine (CC).[6] If PJM and stakeholders accept this recommendation, they will need estimates for both a CT and a CC in setting the VRR curve. If they do not, PJM will still need both estimates for calculating offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[7]

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[4] The exact quantity on the VRR curve where the price equals Net CONE is actually 1% above the IRM reliability requirement in order to reduce the likelihood of deficient outcomes. However, our concurrently-released VRR Curve report finds that even with this adjustment, the existing VRR curve is likely to fall short of reliability objectives. For more details, see 2014 VRR Report.

[5] PJM 2014 OATT, Section 5.10 a.

[6] 2014 VRR Report.

[7] PJM 2014 OATT, Section 5.14 h.

We were asked to assist PJM and stakeholders in this triennial review by developing CONE estimates for new CT and CC plants in each of the five CONE Areas. In this study, we define the CT and CC reference technologies and estimate their CONEs in the five CONE Areas.

B. Analytical Approach

Our analytical starting point for estimating CONE is a detailed characterization of the CC and CT plants in each CONE Area to reflect the technologies, plant configurations, and locations where developers are most likely to build. While the turbine technology for each plant is specified in the tariff (GE 7FA), we provide a review of the most recent gas-fired generation projects in PJM and the U.S. to determine whether this assumption is still relevant to the PJM market.[8] The key configuration variables we define for each plant include the number of gas and steam turbines, NO_x controls, duct firing and power augmentation, cooling systems, dual-fuel capability, and gas compression. We selected specific plant characteristics based on: our analysis of the predominant practices among recently-developed plants; our analysis of technologies, regulations, and infrastructure; and our experience with previous projects. Key site characteristics include proximity to high voltage transmission infrastructure and interstate gas pipelines, siting attractiveness as indicated by units recently built or currently under construction, and availability of vacant industrial land. Our analysis for selecting plant locations and technical specifications for each CONE Area is presented in Section II.

We developed comprehensive, bottom-up estimates of the costs of building and maintaining the specified plants in Section III. S&L estimated *plant proper* capital costs—equipment, materials, labor, and EPC contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the *owner's* capital costs, including gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component.

We estimated annual fixed operations and maintenance (fixed O&M) costs, including labor, materials, property tax, insurance, asset management costs, and working capital. The results of this analysis are presented in Section IV.

Next, we translated these costs into the capital and fixed cost recovery the plant would have to earn in its first year, which we call the "Cost of New Entry" ("CONE"). CONE depends on the estimated capital and fixed O&M costs as well as the estimated cost of capital consistent with the project's risk and the assumed economic life of the asset. CONE also depends on developers' long-term market view and how it impacts the cost recovery path for the plant, specifically whether they can expect to earn as much in later years as in earlier years. We present our financial assumptions for calculating CONE in Section V.

Finally, in Section VI, we offer CONE calculations based on two different assumed cost recovery paths: one in which future revenues are assumed to remain constant in real-terms, which we recommend, as explained in our 2014 VRR Report; and one in which future revenues are assumed to

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8 PJM, *PJM Manual 18: PJM Capacity Market*, Revision: 22, p. 21.

remain constant in nominal terms, which PJM has historically assumed. The level-real assumption results in lower CONE values.

The Brattle authors and Sargent & Lundy collaborated on completing this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Determination of Reference Technologies

Similar to the 2011 PJM CONE Study, we determined the characteristics of the reference technology primarily based on a "revealed preferences" approach that relies on our review of the choices that actual developers found to be most feasible and economic. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional review of the underlying economics, regulations, and infrastructure, and S&L's experience. For selecting the reference technology location within each CONE Area, we modified our analysis from the 2011 PJM CONE Study to take into account a broader view of potential sites that can be considered feasible and favorable for new plant development. As the basis for determining most of the selected reference technology specifications, we updated our analysis from the 2011 study by examining CT and CC plants built in PJM and the U.S. since 2008, including plants currently under construction. We characterized these plants by size, plant configuration, turbine type, NO_x controls, CO catalyst, duct firing, dual-fuel capability, and cooling system.

A. Locational Screen

The Open Access Transmission Tariff (OATT) requires a separate CONE parameter in each of five CONE Areas as summarized in Table 3.[9]

Table 3
PJM CONE Areas

CONE Area	Transmission Zones	States
1 Eastern MAAC	AECO, DPL, JCPL, PECO, PSEG, RECO	NJ, MD, DE
2 Southwest MAAC	BGE, PEPCO	MD, DC
3 Rest of RTO	AEP, APS, ATSI, ComEd, DAY, DEOK, DQL	WV, VA, OH, IN, IL, KY, TN, MI
4 Western MAAC	MedEd, Penelec, PPL	PA
5 Dominion	Dominion	VA, NC

9 PJM 2014 OATT, Section 5.10 a.

We conducted a locational screening analysis to identify feasible and favorable locations for each of the five CONE Areas. Our approach for identifying the representative locations within each CONE Area included three steps:

1. We identified candidate locations based on revealed preference of actual plants built since 2002 or recently proposed plants to identify the areas of primary development, putting more weight on recent projects.

2. We sharpened the definition of likely areas for future development, depending on the extent of information available from the first step. For CONE Areas where recent projects provide a clear signal of favored locations, we only excluded counties that would appear to be less attractive going forward, based on environmental constraints or economic costs (absent special offsetting factors we would not know about). For CONE Areas where revealed preference data is weak or scattered, we identified promising locations from a developer perspective based on proximity to gas and electric interconnections and key economic factors such as labor rates and energy prices

3. This approach results in identifying a specified area that spans a wider range of counties than the previous CONE study. For this reason, we developed cost estimates for each CONE Area by taking the average of cost inputs (*e.g.*, labor rates) across the specified locations.

We describe next the results of the screening analysis that we used for determining the reference plant locations in each CONE Area. The locations chosen for each CONE Area are shown in Figure 1. To provide a more detailed description of the specified locations, we show the cities used for estimating labor rates in Table 4.

Our review of recent development in CONE Area 1 Eastern MAAC (EMAAC) resulted in identifying two areas where significant development has occurred since 2002. The first area is in northern New Jersey along the I-95 corridor, where four plants have been built since 2002, including the 2012 Kearny peaking facility, and three additional CC plants are in the planning phase. The second area includes Philadelphia and the southernmost New Jersey counties, where two CC plants have been built and three additional facilities are in the planning phase. With significant development in both areas and no reason for excluding either due to environmental or economic reasons, we include both as our reference locations.

In CONE Area 2 Southwest MAAC (SWMAAC), four new projects are in various stages of development (three CCs and one CT) in the area around Waldorf, Maryland including portions of Charles and Prince George's counties. Despite the strong indication of developers' preferences to build in this area, limits on the existing gas infrastructure are expected to create gas supply challenges that will be addressed in the cost estimation section of this study. There is limited development in the rest of the region.

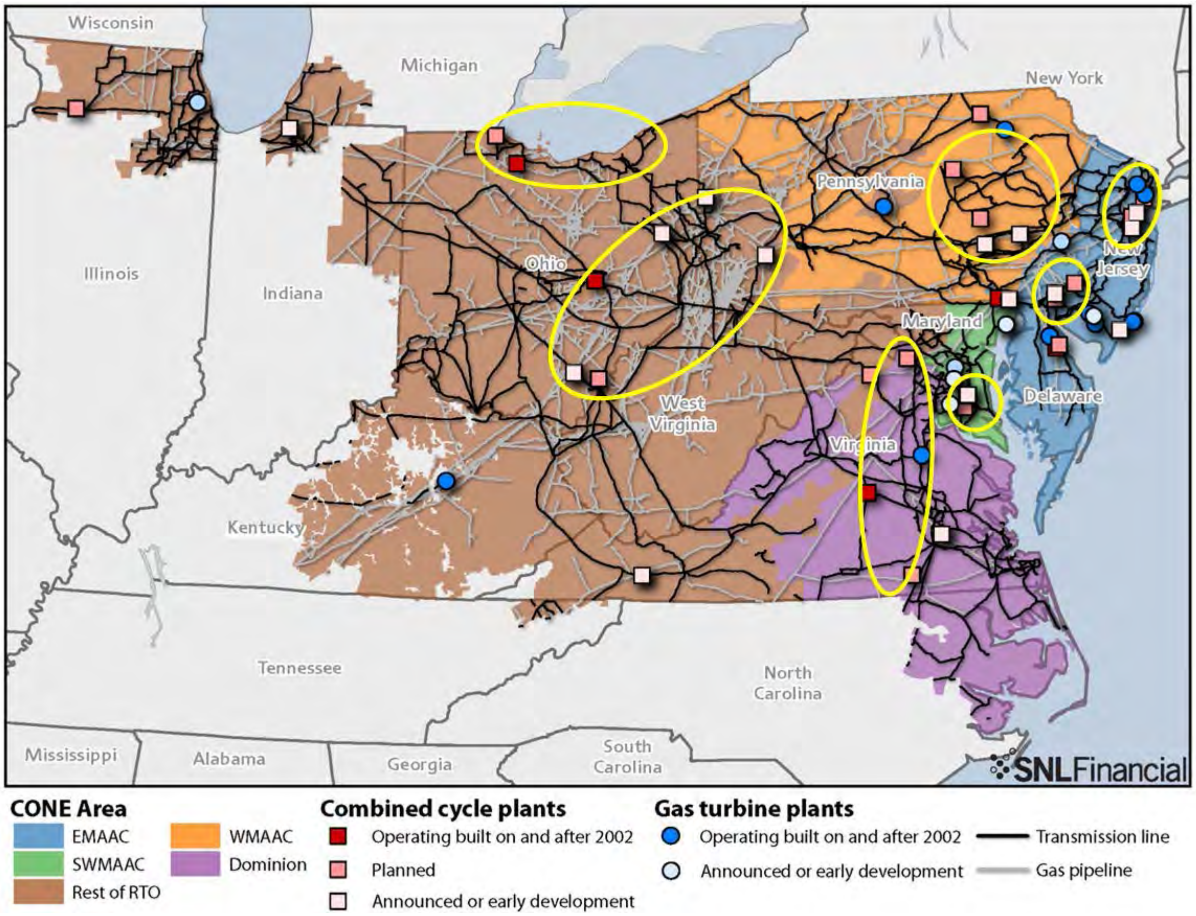
For the larger CONE Area 3 Rest of RTO CONE Area, the revealed preferences approach indicated three favored areas based on our review of recently built or in-development plants: northern Illinois, northwest Ohio, and the Pennsylvania, Ohio, and West Virginia portions of the Ohio River valley.

Further analysis resulted in excluding northern Illinois due to relatively low energy revenues and high labor costs, which disfavor this area relative to the others identified. For these reasons, we chose the counties in northwest Ohio and the Ohio River valley region for estimating costs in the Rest of RTO Area.

In CONE Area 4 **Western MAAC (WMAAC)**, developers have demonstrated a willingness to build primarily in mid-eastern Pennsylvania, including areas around Allentown, Scranton, and Lancaster. Projects include the Mehoopany peaking facilities added in 2013 and five CC facilities in different planning stages within this region. We found no reasons to narrow or expand the specified area further.

In CONE Area 5 **Dominion**, we identified two promising areas, one with several operating plants (in north-central Virginia) and the other with two proposed plants (south-central Virginia), both of which appear to meet developers' gas and electric infrastructure needs. We expanded the region considered to include both areas as well as the counties in between, which amounts to the counties along and just west of I-95 in Virginia.

Figure 1
Results of Locational Screening for each CONE Area



Source:
Map provided by SNL Financial
Data on operating and planned projects downloaded from SNL Financial between November 2013 and March 2014.

Table 4
CONE Area Labor Pools

CONE Area				
1 EMAAC	**2 SWMAAC**	**3 Rest of RTO**	**4 WMAAC**	**5 Dominion**
Jersey City, NJ	Washington, DC	Pittsburgh, PA	Reading, PA	Petersburg, VA
Newark, NJ	Annapolis, MD	New Castle, PA	Williamsport, PA	Richmond, VA
Camden, NJ	Alexandria, VA	Steubenville, OH	Wilkes-Barre, PA	Alexandria, VA
New Brunswick, NJ		Cleveland, OH		
Newark, DE		Lorain, OH		
Wilmington, DE		Toledo, OH		
Philadelphia, PA		Wheeling, WV		
		Parkersburg, WV		
		Huntington, WV		

We calculate the plant operating characteristics (*e.g.*, net capacity and heat rate) of the reference technologies using turbine vendors' performance estimation software for the combustion turbines output and GateCycle software for the remainder of the CC plant. For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[10] The assumed ambient conditions for each location are shown in Table 5.

Table 5
Assumed PJM CONE Area Ambient Conditions

CONE Area	Elevation *(ft)*	Max. Summer Temp *(deg F)*	Relative Humidity *(%RH)*
1 Eastern MAAC	110	94.0	44.2
2 Southwest MAAC	150	95.2	45.2
3 Rest of RTO	1,070	89.5	50.2
4 Western MAAC	1,200	91.0	46.0
5 Dominion	390	93.7	47.2

Source:
Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

B. Plant Size, Configuration and Turbine Model

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7FA as the turbine model), we provide a review of the most recent gas-fired generation projects in PJM and the U.S. to confirm this assumption.[11] We reviewed CT and CC projects built or currently proposed in PJM and across the U.S. to determine the configuration, size, and turbine types for the reference technologies.

[10] The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition, Dordrecht, Holland: D. Reidel Publishing Company, 1981.

[11] PJM 2014 OATT, Attachment DD, Section 2, see definition for Reference Resource.

For the CT, we found that frame-type CTs (GE 7FA and Siemens-501) have been the predominant turbine types built in PJM and throughout the U.S. since 2002, as shown in Table 6. We also found a recent trend toward aeroderivative turbines (GE LMS100 and LM6000). The total capacity of new aeroderivative turbines built in PJM since 2008 is approximately the same as frame-type turbines over the same time period.

Table 6
Turbine Model of CT Turbines Built and Under Construction in PJM and the U.S.

Turbine Model	Turbine Class	Online After 2002				Online After 2008			
		PJM		U.S.		PJM		U.S.	
		(count)	*(MW)*	*(count)*	*(MW)*	*(count)*	*(MW)*	*(count)*	*(MW)*
General Electric-7FA	Frame	31	4,807	105	16,132	3	481	16	2,518
General Electric-LM6000	Aeroderivative	11	1,615	27	4,088	7	317	80	3,669
General Electric-LMS100	Aeroderivative	15	1,165	135	10,057	3	273	28	2,606
Rolls Royce Corp-Trent 60	Aeroderivative	2	148	13	853	2	120	4	225
Siemens-501	Frame	22	949	198	8,784	0	0	0	0
Siemens-V84	Frame	3	273	29	2,688	0	0	0	0
General Electric-7EA	Small Frame	2	120	4	225	0	0	10	742
General Electric-MS6001	Small Frame	9	1,179	16	1,903	0	0	0	0

Source:
Data downloaded from Ventyx's *Energy Velocity Suite* between November 2013 and March 2014

We find that the frame-type GE 7FA turbine to be a reasonable choice for the PJM CT reference technology as it is the turbine model that has been built the most in PJM since 2008 and has a lower turbine cost per-kilowatt than the aeroderivative models. While we believe the turbine model should change if the market reveals such a preference, we do not find a basis to make a change in turbine model for PJM in the current study from the tariff specification. The reference CT plant configuration is assumed to have two turbines at one site (a "2×0") to capture savings from the economies of scale, which is also consistent with the tariff. We specify the CT reference technology capacity and heat rate in the CONE Areas based on the local conditions assumptions in Table 5, with the CT capacities ranging from 395 to 411 MW.

For the CC reference technology, the predominant size of recently developed CC plants is 500 to 700 MW (including duct firing capacity, if any), primarily in a 2×1 configuration, as shown in Table 7.

Table 7
PJM CC Under Construction or Built
(a) Since 2002

	< 300 *(MW)*	**300-500** *(MW)*	**500-700** *(MW)*	**700-900** *(MW)*	**> 900** *(MW)*	**Total** ***(MW)***
1 x 1	1,902	1,839	0	0	0	**3,741**
2 x 1	42	466	11,186	700	0	**12,394**
3 x 1	198	0	2,240	3,060	2,255	**7,754**
Total	**2,141**	**2,305**	**13,426**	**3,760**	**2,255**	**23,888**

(b) Since 2010

	< 300 *(MW)*	**300-500** *(MW)*	**500-700** *(MW)*	**700-900** *(MW)*	**> 900** *(MW)*	**Total** ***(MW)***
1 x 1	762	1,839	0	0	0	**2,601**
2 x 1	0	0	2,446	700	0	**3,146**
3 x 1	0	0	545	0	1,329	**1,874**
Total	**762**	**1,839**	**2,991**	**700**	**1,329**	**7,621**

Sources and Notes:
Data downloaded from Ventyx's Energy Velocity Suite between November 2013 and March 2014

The turbine model most often installed on recent CC plants is the GE 7FA, as shown in Table 8. The Siemens and GE turbines are similar designs that have both been competing for market share. While we find there are reasons to use either turbine manufacturer, we selected the GE 7FA for the PJM CONE due to its previous use in estimating CONE in PJM. Based on the local ambient condition assumptions in Table 5, we specify the 2×1 CC reference technology's summer capacity to range from 576–595 MW (prior to considering supplemental duct firing, as discussed in the next section).

Table 8
Turbine Model of CC Plants Built and Under Construction Combined Cycle Plants in PJM Online Since 2002

Turbine Model	Installed Capacity *(MW)*
General Electric 7FA	12,977
Siemens V84.2	2,240
Siemens SGT6-8000H	1,530
Siemens AG-501F	1,433
Mitsubishi M501GAC	1,329
Siemens SCC6-5000F	975
General Electric 7FB	758
Simens 501FD	559
General Electric Other	198
Other	1,889

Sources and Notes:
Data downloaded from Ventyx's Energy Velocity Suite between November 2013 and March 2014

We considered whether a flexible CC design, such as the GE Flex60, should be specified as the configuration of the CC reference technology. Our review of the performance of the conventional packages versus the flexibility package found that the benefits of the improved flexible design are largely offset by its incremental costs, such that the Net CONE calculation for the conventional and flexible designs would likely be similar. In addition, there is limited data available for accurately calculating either the capital costs or the E&AS revenues of the flexible design due to its recent introduction into the market. For these reasons, we assumed a conventional plant design for the CC. If the flexible design continues to be considered and built by developers in the next several years, PJM could consider using such a design in future CONE updates.

C. Detailed Technical Specifications

1. Combined Cycle Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell mechanical draft cooling tower, based on the predominance of cooling towers among new CCs and S&L recommendation. Our review of EIA-860 data found that all CC plants with a specified cooling system had a cooling tower installed, as shown in Table 9.

Table 9
Cooling System for CC Plants in PJM Under Construction or Built Since 2008

State	Once-Through *(MW)*	Cooling Tower *(MW)*	Dry Cooling *(MW)*	Unknown *(MW)*
Pennsylvania	0	545	0	126
Virginia	0	589	0	1,329
New Jersey	0	1,350	0	0
Delaware	0	309	0	62
Ohio	0	1,207	0	0
Illinois	0	0	0	573
Indiana	0	0	0	0
Total	**0**	**4,001**	**0**	**2,091**

Sources and Notes:

Based on 2012 Form EIA-860 Data; cooling tower includes recirculating with forced, induced and natural cooling towers.

We reviewed whether reclaimed water from municipal waste treatment centers would be available for use in the cooling systems to avoid environmental issues with withdrawing fresh water. Our review of the availability of reclaimed water indicated that EMAAC and SWMAAC have at least one treatment center per county, such that reclaimed water can be considered generally available. In WMAAC and Dominion, we found that reclaimed water can be available on a site-specific basis. Although not every county has such a facility, we assume reclaimed water is prevalent enough for the reference technology to use reclaimed water in each of these CONE Areas. For the Rest of RTO Area, municipal waste treatment facilities are much less common such that withdrawals from ground or surface water would be necessary. In addition to environmental drivers for using reclaimed water, building the piping and treatment facilities required for ground or surface water costs $500k to $1 million more than for reclaimed water, depending on the location.

2. Combined-Cycle Duct Firing

For the reference CC plant, supplemental firing of the steam generator, also known as "duct firing," increases steam production and hence increases the output of the steam turbine. Duct firing is common, although there is no standard optimized design. The decision to incorporate supplemental firing with the plant configuration and the amount of firing depends on the owner's preference and perceived economic value.

We assumed the reference CC plant would add duct firing sufficient to increase the net plant capacity by 73 MW, or 12%. This is close to the average of CC plants constructed since 2002 or in development in the U.S. but less than in PJM, as shown in Table 10. Due to the relatively small number of plants built in PJM since 2002, we chose to weigh the U.S. value more heavily.

Table 10
Duct-Firing Capability of CC Plants Constructed Since 2002 and In Development

	Installed Capacity *(MW)*	No. of Plants *(count)*	Avg. Plant Size *(MW)*	Avg. Duct Fired Capacity *(MW)*	Duct Fired Addition % *(%)*
PJM	2,020	3	673	93	16%
U.S.	35,865	56	640	77	14%

Sources and Notes:
Data on duct firing capacities for CC plants downloaded from Ventyx's Energy Velocity Suite in 2014

Including duct firing increases the net capacity of the plant but reduces efficiency due to the higher incremental heat rate of the supplemental firing (when operating in duct firing mode) and the reduced efficiency of steam turbine (when not operating at full output). The estimated heat rates and capacities take account for this effect.

3. Power Augmentation

Based on our analysis in the 2011 PJM CONE Study, we included evaporative coolers downstream of the filtration system to lower the combustion turbine inlet air temperature during warm weather operation. This increases turbine output and efficiency for only a small increase in capital cost. In addition, the combustion turbines in both simple- and combined-cycle arrangements are equipped with an inlet filtration system to protect from airborne dirt and particles. Evaporative coolers and associated equipment add $3 million per combustion turbine to the capital costs.

4. Emissions Controls

Emission control technology requirements for new major stationary sources are determined through the New Source Review (NSR) pre-construction permitting program. The NSR permitting program evaluates the quantity of regulated air pollutants the proposed facility has the potential-to-emit and determines the appropriate emission control technology/practice required for each air pollutant. The regulated air pollutants that will have the most impact on emission control technology requirements for new CTs and CCs are nitrogen oxides (NO_x) and carbon monoxide (CO).

NO_x and CO emissions from proposed gas-fired facilities located in PJM will be evaluated through two different types of NSR permitting requirements:

- Non-attainment NSR (NNSR) for NO_x emissions; and
- Prevention of Significant Deterioration (PSD) for CO emissions.

NO_x emissions are evaluated through the NNSR permitting requirements, because NO_x (a precursor to ozone) is treated as a non-attainment air pollutant for all areas within the Ozone Transport Region

(OTR) regardless of ozone attainment status.[12] Except for Rest of RTO, all of the CONE Areas in PJM are within OTR, and thus, emissions of NO_x from proposed facilities are treated as a non-attainment air pollutant and evaluated through non-attainment new source review (NNSR). The Rest of RTO is currently non-attainment for 8-hour ozone.

New CTs and CCs with no federally enforceable restrictions on operating hours are deemed a major source of NO_x emissions, and therefore, trigger a Lowest Achievable Emission Rates (LAER) analysis to evaluate NO_x emission control technologies. The NO_x emission control technology required by the LAER analysis is likely to be a selective catalytic reduction (SCR) system. SCR systems are widely recognized as viable technology on aeroderivative and smaller E-class frame combustion turbines and have more recently been demonstrated on F-class frame turbines. Our assumptions of an SCR on the F-class turbine is supported by the Commission's recent determination in approving the NYISO's assumption of F-class turbine with SCR as the proxy unit for its proposed Demand Curves that "the record of evidence presented in support of the frame unit with SCR is adequate in order to find that NYISO reasonably concluded that the F class frame with SCR is a viable technology."[13] In addition, we assume inlet air filters and dry low NO_x burners, which are also necessary to achieve the required emissions reductions.

CO emissions are evaluated through the PSD permitting requirements, because PJM is designated as an attainment area for CO. New combustion turbine facilities with no operating hour restrictions have the potential-to-emit CO in a quantity that exceeds the significant emission threshold for CO, and therefore, trigger a Best Available Control Technology (BACT) analysis to evaluate CO emission control technologies. The CO emission control technology required as a result of a BACT analysis is likely to be an oxidation catalyst (CO Catalyst) system.

For these reasons, we assume an SCR and a CO Catalyst system as the likely requirements resulting from the NSR permitting program for new gas-fired facilities proposed in all CONE Areas. The most significant change from the 2011 PJM CONE Study is assuming an SCR on the CT in Dominion, which is being added due to additional consideration of the regulatory requirements of being located in the Ozone Transport Region. The CO Catalyst system in all areas is expected to increase costs of emissions control equipment by $2.4 million (in 2014 dollars) over the 2011 CONE study.

5. Dual Fuel Capability, Firm Gas Contracts, and Gas Compression

We largely maintained our assumption from the 2011 PJM CONE Study that the reference CT and CC plants would install dual-fuel capability in all CONE Areas except for the Rest of RTO Area, based on a review of recent projects. The Rest of RTO Area is assumed to be single-fuel, although at PJM's request we also calculated CONE estimates for Rest of RTO with dual-fuel capability in Section VI).

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[12] The Ozone Transport Region (OTR) includes all of New England as well as Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, and portions of Virginia.

[13] Federal Energy Regulatory Commission (2014). Order 146 FERC ¶ 61,043, Issued January 28, 2014, at paragraph 58. Docket No. ER14-500-000.

Our assumptions have changed only for CCs in SWMAAC, where we do not assume dual fuel, consistent with the CPV St. Charles project under development there.[14] Instead, we assume firm transportation service on the Dominion Cove Point (DCP) pipeline. We understand from shippers that the DCP pipeline is capacity-constrained and also has limited operational flexibility. Firm transportation avoids interruptions, although it may not provide additional operational flexibility. Firm transportation also largely eliminates the value of dual-fuel capability (except when the three major interstate pipelines to which the DCP pipeline is connected become constrained). However, we do not assume firm transportation for the reference CT plant since firm gas is unlikely to be economic for a plant that operates at a low capacity factor. We assume the CT will have dual-fuel capability.

To be capable of firing gaseous and liquid fuels, the plants are assumed to be equipped with enough liquid fuel storage and infrastructure on-site for three days of continuous operation. Dual-fuel capability also requires the combustion turbines to have water injection nozzles to reduce NOx emissions while firing liquid fuel. These modifications as well as the costs associated with fuel oil testing, commissioning, inventory, and the capital carrying charges on the additional capital costs contribute to the overall costs for dual-fuel capability. The incremental cost is approximately $22 million for the CC and $24 million for the CT (in 2014 dollars), including equipment, labor, and materials, indirect costs, and fuel inventory.[15] That contributes approximately $9,500/MW-year to the CONE for the CT and $5,600/MW-year for the CC (in 2018 dollars and in level-nominal terms). For CCs in SWMAAC, firm transportation avoids these costs, but the firm transportation itself costs about twice as much, as discussed in Section IV.A.5.

Based on our analysis in the 2011 PJM CONE Study, we determined gas compression would not be needed for new gas plants with frame-type combustion turbines located near and/or along the major gas pipelines selected in our study. The frame machines generally operate at lower gas pressures than the gas pipelines.

6. Black Start Capability

Based on our analysis in the 2011 PJM CONE Study, we did not include black start capability in either the CC or CT reference units because few recently built gas units have this capability.

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14 Environmental Consulting & Technology, Inc. (2011), Demonstration of Compliance with Air Quality Control Requirements and Request for Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Approvals: CPV St. Charles Project, 725-MW Combined Cycle Project, Prepared for Competitive Power Ventures Maryland, LLC (CPV), ECT No. 110122-0200, August 2011.

15 The incremental cost of dual-fuel capability is higher for the CT due to the cost of the demineralized water package that is already assumed to be installed for the CC for its steam cycle.

7. Electrical Interconnection

While all CONE Areas have a variety of transmission voltages, both lower and higher than 345 kV, we selected 345 kV as the typical voltage for new CT and CC plants to interconnect to the transmission grid in PJM. The switchyard is assumed to be within the plant boundary and is counted as an EPC cost under "Other Equipment," including generator circuit breakers, main power and auxiliary generator step-up transformers, and switchgear. All other electric interconnection equipment, including generator lead and network upgrades, is included separately under Owner's Costs, as presented in Section III.B.4.

D. Summary of Reference Technology Specifications

Based on the assumptions discussed above, the technical specifications for the CT and CC reference technology are shown in Table 11 and Table 12. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 5.

Table 11
Summary of CT Reference Technology Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7FA.05
Configuration	2 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	396 / 393 / 385 / 383 / 391 *
Net Heat Rate (HHV in Btu/kWh)	10,309 / 10,322 / 10,297 / 10,296 / 10,317 *
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	Dual / Dual / Single / Dual / Dual *
Firm Gas Contract	No
Special Structural Req.	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and Notes:
See Table 5 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* Power ratings and heat rates are for EMAAC, SWMAAC, Rest of RTO, WMAAC, and Dominion CONE Areas, respectively

Table 12
Summary of CC Reference Technology Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7FA.05
Configuration	2 x 1
Cooling System	Cooling Tower *
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
w/o Duct Firing	595 / 591 / 578 / 576 / 587 **
with Duct Firing	668 / 664 / 651 / 649 / 660 **
Net Heat Rate (HHV in Btu/kWh)	
w/o Duct Firing	6,800 / 6,811 / 6,791 / 6,792 / 6,808 **
with Duct Firing	7,028 / 7,041 / 7,026 / 7,027 / 7,039 **
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	Dual / Single / Single / Dual / Dual **
Firm Transportation Service	No / Yes / No / No / No **
Special Structural Req.	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and Notes:
See Table 5 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* CONE Area 3 uses ground/surface water; all others use reclaimed water for cooling
** For EMAAC, SWMAAC, Rest of RTO, WMAAC, and Dominion CONE Areas, respectively

III. Capital Cost Estimates

Capital costs are those costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs, include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2014 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct simple and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost in 2018 dollars by escalating the 2014 cost data using reasonable escalation rates. The 2018 "installed cost" is the present value of the construction period cash flows as of the end of the construction period and is calculated using the monthly drawdown schedule and the cost of capital for the project.

A. Plant Proper Capital Costs

1. Plant Developer and Contractor Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

2. Equipment and Sales Tax

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines, where applicable. The major equipment includes "owner-furnished equipment" (OFE) that the owner purchases through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. A sales tax rate specific to each CONE Area is applied to the sum of major equipment and other equipment to account for the sales tax on all equipment.

3. Labor and Materials

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, and field engineering, start-up, and commissioning services. "Materials" include all construction material associated with the EPC scope of work, material freight costs, and consumables during construction.

The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, the labor rates have been developed by S&L through a survey of the prevalent wages in each region in 2014, including both union and non-union labor. This approach differs from the 2011 PJM CONE Study, in which a single assumption of the labor type was specified for each CONE Area. The change in determining wages and productivity rates results in higher labor costs in SWMAAC and Dominion, which were assumed to use strictly non-union labor in the 2011 study. The updated approach provides a better representation of the labor force that will include labor from both pools. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type.

4. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. Capital cost estimates include an EPC contractor fee of 10% and 12% of EPC costs for CT and CC facilities, respectively.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of EPC costs.

The EPC contractor fee and contingency rates are based on S&L's proprietary project cost database. The EPC contingency rate (10%) is higher than the value used in the 2011 PJM CONE study (4% contingency charged by the EPC, plus an additional 3% of EPC costs for change orders that was included as part of the Owner's Contingency) due to input received from stakeholders following the issuance of that study. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.6% of the pre-contingency overnight capital costs, compared to 6.4% in the 2011 study.

B. Owner's Capital Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

1. Project Development and Mobilization and Startup

Project development costs include items such as development costs, oversight, legal fees, and emissions reductions credits that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

2. Net Start-Up Fuel Costs During Testing

Before commencing full commercial operations, new generation plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas and ultra-lower sulfur diesel (ULSD) if dual fuel capability is specified. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas and fuel oil consumption, and will receive revenues for its energy production. We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume Transco Zone 6 Non-New York (Z6 NNY) prices apply for all CONE Areas; forecast Z6 NNY natural gas prices using traded futures on NYMEX (CME Group) until March 2015 and grow the basis differentials at the rate of inflation into 2018.
- **Fuel Oil:** rely on No. 2 fuel oil futures for New York harbor through January 2018; escalate fuel oil prices between January 2018 and an assumed fuel delivery date of March and April 2018 based on the escalation in Brent crude oil futures over the same date range.[16]
- **Electric Energy:** estimate prices based on PJM Eastern Hub for EMAAC, and PJM Western Hub for all other CONE Areas; calculate monthly 2015 market heat rates based on electricity and gas futures in each location and assume market heat rates remain constant to 2018; average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

[16] Data from Bloomberg, representing trade dates 12/22/2013 to 2/20/2014.

Table 13
Startup Production and Fuel Consumption During Testing

	Energy Production			Fuel Consumption						
	Energy Produced *(MWh)*	Energy Price *($/MWh)*	Energy Sales *($m)*	Natural Gas *(MMBtu)*	Natural Gas Price *($/MMBtu)*	NG Cost *($m)*	Fuel Oil *(MMBtu)*	Fuel Oil Price *($/MMBtu)*	Fuel Oil Cost *($m)*	Total Cost *($m)*
Gas CT										
1 Eastern MAAC	206,924	$42.3	$8.8	1,996,322	$5.49	$11.0	99,816	$17.9	$1.8	$4.0
2 Southwest MAAC	206,625	$38.7	$8.0	1,993,443	$5.49	$10.9	99,672	$17.9	$1.8	$4.7
3 Rest of RTO	190,360	$38.7	$7.4	1,928,726	$5.49	$10.6	n.a.	$17.9	$0.0	$3.2
4 Western MAAC	198,935	$38.7	$7.7	1,919,816	$5.49	$10.5	95,991	$17.9	$1.7	$4.6
5 Dominion	204,852	$38.7	$7.9	1,976,332	$5.49	$10.9	98,817	$17.9	$1.8	$4.7
Gas CC										
1 Eastern MAAC	691,621	$42.3	$29.3	3,958,589	$5.49	$21.7	197,929	$18.0	$3.6	-$4.0
2 Southwest MAAC	657,777	$38.7	$25.4	3,952,938	$5.49	$21.7	n.a.	$18.0	$0.0	-$3.7
3 Rest of RTO	639,138	$38.7	$24.7	3,824,235	$5.49	$21.0	n.a.	$18.0	$0.0	-$3.7
4 Western MAAC	668,436	$38.7	$25.8	3,806,568	$5.49	$20.9	190,328	$18.0	$3.4	-$1.5
5 Dominion	685,484	$38.7	$26.5	3,918,677	$5.49	$21.5	195,934	$18.0	$3.5	-$1.5

Sources and Notes:
Energy production and fuel consumption estimated by S&L
Energy and fuel prices are forecasted based on futures downloaded from Ventyx's Energy Velocity Suite in 2014

3. Gas Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 14. We identified appropriate lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs.[17]

We assume the gas interconnection will require a metering station and a five mile lateral connection, similar to 2011 PJM CONE Study. From this data, we estimate that gas interconnection costs will be $20.5 million (in 2014 dollars) for all plants, as we found no relationship between pipeline width and per-mile costs in the project cost data.

17 The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

Table 14
Gas Interconnection Costs

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(2014$)*	Pipeline Cost *($m/mile)*	Meter Station *(Y/N)*	Meter Station Cost *(2014m$)*
Delta Lateral Project	PA	2010	16	3.4	$9,944,085	$2.91	Y	$3.5
Carty Lateral Project	OR	2014	20	24.3	$52,032,000	$2.14	Y	$2.3
South Seattle Delivery Lateral Expansion	WA	2013	16	4.0	$13,788,201	$3.4	N	n.a.
Bayonne Delivery Lateral Project	NJ	2012	20	6.2	$13,891,136	$2.2	Y	$3.9
North Seattle Delivery Lateral Expansion	WA	2012	20	2.2	$11,792,028	$5.4	Y	$1.4
FGT Mobile Bay Lateral Expansion	AL	2011	24	8.8	$28,179,328	$3.2	Y	$2.6
Northeastern Tennessee Project	VA	2011	24	28.1	$133,734,240	$4.8	Y	$2.9
Hot Spring Lateral Project	TX,AR	2011	16	8.4	$34,261,849	$4.1	Y	$3.8
Average						**$3.5**		**$2.9**

Sources and Notes:

A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp)

4. Electric Interconnection

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs do not always occur, but are incurred when improvements, such as replacing substation transformers, are required.

In addition to the interconnection projects included in the 2011 PJM CONE study, we added projects recently constructed or under construction that are representative of interconnection costs for a new gas combined-cycle or combustion turbine. Table 15 summarizes the project costs used for estimating electric interconnection costs for this study. Based on the capacity-weighted average, electric interconnection cost is at approximately $12 million for CTs and $20 million for CCs, both expressed in 2014 dollars.

Table 15
Electric Interconnection Costs in PJM

Plant Size	Observations	Electrical Interconnection Cost	
		Average	Average
	(count)	*(2014$m)*	*(2014$/kW)*
100-300 MW	5	$3.8	$26.7
300-500 MW	3	$11.3	$31.4
500-800 MW	13	$19.5	$30.9
Capacity Weighted Average	**21**	**$17.4**	**$30.0**

Sources and Notes:
Confidential project-specific cost data provided by PJM.

5. Land

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 20 acres for sale in each selected county. There is a wide range of prices within the same CONE Area as shown in Table 16, which means that land costs can vary significantly among plants.

Table 16
Current Land Asking Prices

CONE Area	Current Asking Prices	
	Range	Observations
	(2013 $000/acre)	*(count)*
1 EMAAC	$10-$119	8
2 SWMAAC	$19-$150	10
3 RTO	$10-$100	22
4 WMAAC	$5-$100	14
5 Dominion	$13-$163	9

Sources and Notes:
We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

Table 17 shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location. We assume that 30 acres of land are needed for CT and 40 acres for CC.

Table 17
Cost of Land Purchased

CONE Area	Land Price ($/acre)	Plot Size Gas CT (acres)	Plot Size Gas CC (acres)	Cost Gas CT ($m)	Cost Gas CC ($m)
1 EMAAC	$66,300	30	40	$1.99	$2.65
2 SWMAAC	$73,900	30	40	$2.22	$2.96
3 RTO	$38,100	30	40	$1.14	$1.52
4 WMAAC	$41,600	30	40	$1.25	$1.66
5 Dominion	$54,300	30	40	$1.63	$2.17

Sources and Notes:
We assume land is bought in 2014, *i.e.*, 6 months to 1 year before the start of construction.

6. Fuel and Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel working capital is 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

We calculated the cost of the fuel inventory in areas with dual-fuel capability assuming a three day supply of ULSD fuel will be purchased prior to operation at a cost of $2.52/gallon, or $18/MMBtu (in 2018 dollars), based on current futures prices.[18]

7. Owner's Contingency

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* We assumed an owner's contingency of 9% of Owner's Costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

8. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are also part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs.[19]

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18 EIA, Electric Power Monthly, 2013.

19 As discussed in the Financial Assumptions section, we assume the plant is financed through a 60% debt and 40% equity capital structure.

C. Escalation to 2018 Installed Costs

1. Escalation

We escalated the 2014 estimates of overnight capital cost components forward to the construction period for a June 2018 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term (approximately 20-year) historical trends relative to the general inflation rate for equipment and materials and labor. The real escalation rate for each cost category was then added to the assumed inflation rate of 2.25% (see Section V.A) to determine the nominal escalation rates, as shown in Table 18.

Table 18
Capital Cost Escalation Rates

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.40%	2.65%
Labor	1.50%	3.75%

Sources and Notes:
Escalation rates on equipment and materials costs are derived from the relevant BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from 2014 overnight costs using the monthly capital drawdown schedule developed by Sargent & Lundy for an online date in June 2018.

However, we escalated several cost items in a different manner:

- **Land**: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2018 online date, the land is thus assumed to be purchased in late 2014 such that current estimates do not require any additional escalation.
- **Net Start-Up Fuel and Fuel Inventories**: no escalation was needed since we forecasted fuel and electricity prices in 2018 dollars.
- **Electric and Gas Interconnection**: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior completion, consistent with the 2011 CONE Study; the interconnection costs have been escalated specifically to these months.

2. Cost of Capital During Construction

S&L has developed monthly capital drawdown schedules over the project development period for each technology. The drawdown schedule is important for calculating debt and equity costs during construction to arrive at a complete "installed cost."

The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2018 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate.[20] By using the ATWACC to calculate the present value, the installed costs will include both the interest during construction from the debt financed portion of the project and the cost of equity for the equity financed portion.

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[20] For CTs, the construction drawdown schedule occurs over 20 months with 80% of the costs incurred in the final 11 months prior to commercial operation. For CCs, the construction drawdown schedule occurs over 36 months with 80% of the costs incurred in the final 20 months prior to commercial operation.

D. CAPITAL COST SUMMARY

Based on the technical specifications for the reference CT and CC in Section II and the capital cost estimates in this section, a summary of the capital costs for an online date of June 1, 2018 is shown below in Table 19 and Table 20.

Table 19
Summary of Capital Costs for CT Reference Technology in Nominal $

	CONE Area				
	1	**2**	**3**	**4**	**5**
	EMAAC	**SWMAAC**	**Rest of RTO**	**WMAAC**	**Dominion**
Capital Costs (in $millions)	*396 MW*	*393 MW*	*385 MW*	*383 MW*	*391 MW*
Owner Furnished Equipment					
Gas Turbines	$98.8	$98.4	$94.0	$98.7	$98.6
SCR	$18.9	$18.7	$17.9	$18.8	$18.8
Sales Tax	$8.2	$7.0	$6.7	$7.1	$7.3
Total Owner Furnished Equipment	**$125.9**	**$124.1**	**$118.6**	**$124.6**	**$124.8**
EPC Costs					
Equipment	$30.9	$30.5	$25.5	$30.8	$30.7
Construction Labor	$71.7	$55.4	$55.3	$54.5	$48.2
Other Labor	$21.2	$19.6	$18.6	$19.6	$19.0
Materials	$9.7	$9.0	$8.6	$9.6	$9.4
Sales Tax	$2.8	$2.4	$2.0	$2.4	$2.5
EPC Contractor Fee	$26.2	$24.1	$22.9	$24.1	$23.5
EPC Contingency	$28.8	$26.5	$25.2	$26.6	$25.8
Total EPC Costs	**$191.4**	**$167.4**	**$158.1**	**$167.6**	**$159.2**
Non-EPC Costs					
Project Development	$15.9	$14.6	$13.8	$14.6	$14.2
Mobilization and Start-Up	$3.2	$2.9	$2.8	$2.9	$2.8
Net Start-Up Fuel Costs	$4.0	$4.7	$3.2	$4.6	$4.7
Electrical Interconnection	$13.0	$12.9	$12.7	$12.6	$12.9
Gas Interconnection	$22.6	$22.6	$22.6	$22.6	$22.6
Land	$2.0	$2.2	$1.1	$1.2	$1.6
Fuel Inventories	$5.3	$5.3	$0.0	$5.1	$5.2
Non-Fuel Inventories	$1.6	$1.5	$1.4	$1.5	$1.4
Owner's Contingency	$6.1	$6.0	$5.2	$5.9	$5.9
Financing Fees	$9.4	$8.7	$8.1	$8.7	$8.5
Total Non-EPC Costs	**$82.9**	**$81.4**	**$70.9**	**$79.6**	**$79.8**
Total Capital Costs	**$400.2**	**$372.9**	**$347.6**	**$371.8**	**$363.8**
Overnight Capital Costs ($million)	**$400**	**$373**	**$348**	**$372**	**$364**
Overnight Capital Costs ($/kW)	**$1,012**	**$948**	**$903**	**$971**	**$931**
Installed Cost ($/kW)	**$1,061**	**$994**	**$947**	**$1,018**	**$977**

Table 20
Summary of Capital Costs for CC Reference Technology in Nominal $

	CONE Area				
	1	**2**	**3**	**4**	**5**
	EMAAC	**SWMAAC**	**Rest of RTO**	**WMAAC**	**Dominion**
Capital Costs (in $millions)	*595 MW*	*591 MW*	*578 MW*	*576 MW*	*587 MW*
Owner Furnished Equipment					
Gas Turbines	$97.3	$92.6	$92.6	$97.2	$97.2
HRSG / SCR	$43.5	$43.5	$43.5	$43.5	$43.5
Sales Tax	$9.9	$8.2	$8.2	$8.4	$8.8
Total Owner Furnished Equipment	**$150.7**	**$144.3**	**$144.3**	**$149.1**	**$149.5**
EPC Costs					
Equipment					
Condenser	$4.2	$4.2	$4.2	$4.2	$4.2
Steam Turbines	$35.5	$35.5	$35.5	$35.5	$35.5
Other Equipment	$60.6	$55.9	$56.4	$60.4	$60.3
Construction Labor	$213.8	$162.1	$164.5	$168.2	$146.9
Other Labor	$45.1	$39.6	$39.9	$41.0	$39.1
Materials	$37.8	$37.8	$37.8	$37.8	$37.8
Sales Tax	$9.7	$8.0	$8.0	$8.3	$8.6
EPC Contractor Fee	$66.9	$58.5	$58.9	$60.6	$57.8
EPC Contingency	$62.4	$54.6	$54.9	$56.5	$54.0
Total EPC Costs	**$536.1**	**$456.2**	**$460.1**	**$472.5**	**$444.3**
Non-EPC Costs					
Project Development	$34.3	$30.0	$30.2	$31.1	$29.7
Mobilization and Start-Up	$6.9	$6.0	$6.0	$6.2	$5.9
Net Start-Up Fuel Costs	-$4.0	-$3.7	-$3.7	-$1.5	-$1.5
Electrical Interconnection	$22.0	$21.8	$21.4	$21.3	$21.7
Gas Interconnection	$22.6	$22.6	$22.6	$22.6	$22.6
Land	$2.7	$3.0	$1.5	$1.7	$2.2
Fuel Inventories	$6.1	$0.0	$0.0	$5.9	$6.0
Non-Fuel Inventories	$3.4	$3.0	$3.0	$3.1	$3.0
Owner's Contingency	$8.5	$7.4	$7.3	$8.1	$8.1
Financing Fees	$18.9	$16.6	$16.6	$17.3	$16.6
Total Non-EPC Costs	**$121.3**	**$106.7**	**$105.0**	**$115.8**	**$114.2**
Total Capital Costs	**$808.0**	**$707.2**	**$709.4**	**$737.4**	**$708.0**
Overnight Capital Costs ($million)	**$808**	**$707**	**$709**	**$737**	**$708**
Overnight Capital Costs ($/kW)	**$1,210**	**$1,065**	**$1,089**	**$1,137**	**$1,073**
Installed Cost ($/kW)	**$1,326**	**$1,168**	**$1,193**	**$1,245**	**$1,176**

IV. Operation and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed operations and maintenance (O&M) costs each year, including property tax, insurance, labor, consumables, minor maintenance, and asset management. Annual fixed O&M costs add to CONE. Separately, we also calculated *variable* operations and maintenance costs (including maintenance, consumables, and waste disposal costs) to inform PJM's future E&AS calculations.

A. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

1. Plant Operation and Maintenance

We estimated the labor, consumables, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including the Electric Power Research Institute (EPRI) State-of-the-Art Power Plant Combustion Turbine Workstation v 9.0 data for existing plants reported on FERC Form 1, confidential data from other operating plants, and vendor publications for equipment maintenance.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. We include monthly LTSA payments as fixed O&M since they are not based on the operation of the plant, and all other costs under the LTSA are considered variable O&M.

2. Insurance and Asset Management Costs

We calculated insurance costs as 0.60% of the overnight capital cost per year, based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of CT and CC plants in operation.

3. Property Tax

To estimate property tax, we researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states. We estimated the property taxes through bottom-up cost estimates that separately evaluated taxes on real property (including land and structural improvements) and personal property (the remainder of the plant) in each location. In this study, we did not incorporate any assumed Payment in Lieu of Taxes (PILOT) agreements. Although PILOT agreements could be executed between an individual plant developer and a county, these agreements are individually negotiated and may not be available on a similar basis for all plants.

Real property is taxed in all states containing reference plant locations we selected for the CONE Area. Personal property is taxed only in SWMAAC (Maryland), Rest of RTO (the portion in Ohio), and Dominion (Virginia). For power plants, the value of personal property tends to be much higher than the value of real property, since equipment costs make up the majority of the total capital cost.

For this reason, property taxes for plants located in states that impose taxes on personal property will be significantly higher than plants located in states that do not.

To estimate real property taxes, we assumed the assessed value of land and structural improvements is the initial capital cost of these specific components. We determined assessment ratios and tax rates for each CONE Area by reviewing the publicly posted tax rates for several counties within the specified locations and by contacting county and state tax assessors (The tax rates assumed for each CONE Area is summarized in Table 21). We multiply the assessment ratio by the tax rate to determine the overall effective tax rate, and apply that rate to our estimate of assessed value. We assume that assessed value of real property will escalate in future years with inflation.

Personal property taxes in the states of Maryland, Ohio, and Virginia were estimated using a similar approach. As with real property, we multiply the local tax rate by the assessment ratio to determine the effective tax rate on assessed value. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years. For example, in Maryland, personal property is subject to straight-line depreciation of 3.3% per year down to a minimum of 25% of the original assessed value.[21]

[21] Maryland Depreciation Regulation Chapter 18, Subtitle 03, Chapter 01, Depreciation .02B(2). Phone conversation with Laura Kittel (410-767-1897) at State Department of Assessments & Taxation in June 2012.

Table 21
Property Tax Rate Estimates for Each CONE Area

		Real Property Tax			Personal Property Tax			
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation
CONE Area		[a]	[b]	[a] X [b]	[c]	[d]	[c] X [d]	[e]
State		*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	
1 EMAAC								
New Jersey	[1]	4.6%	75.2%	3.3%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.8%	50.0%	1.4%	straight-line at 3.3%/yr to 25% min.
3 RTO								
Ohio	[3]	5.6%	35.0%	1.9%	5.6%	24.0%	1.3%	follow annual report "SchC-NewProd (NG)"
Pennsylvania	[4]	3.7%	100.0%	3.7%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[4]	3.7%	100.0%	3.7%	n/a	n/a	n/a	n/a
5 Dominion								
Virginia	[5]	1.0%	95.5%	0.9%	1.0%	95.5%	0.9%	ceiling at 90%; floor at 25%

Sources and Notes:

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Middlesex and Camden Counties. For Middlesex County see: http://www.co.middlesex.nj.us/taxboard/rate-ratio.pdf; for Camden County see: http://www.camdencounty.com/sites/default/files/files/2013%20Rates.pdf and http://www.camdencounty.com/sites/default/files/files/2013%20%20Ratios.pdf.

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJSA § 54:4-1

[2a], [2c] Maryland tax rates estimated as the sum of county and state rates in Charles County and Prince George's County in 2013-2014. Data obtained from Maryland Department of Assessment & Taxation website: http://www.dat.state.md.us/sdatweb/taxrate.html

[2d] Md. Tax-Property Code Ann. 7-237

[2e] Maryland Depreciation Regulation Chapter 18, Subtitle 03, Chapter 01, Depreciation .02B(2). Phone conversation with State Department of Assessments & Taxation in June 2012.

[3a], [3c] Received "Rates of Taxation" from Morgan County auditor's office on Feb 27, 2014, which the auditor confirmed is applicable to both real and personal property; reviewed rates for Perry, Fairfield, and Athens counties, which range from 5–8%.

[3b], [3d] Assessment ratios for real property and electric companies' production personal property found on p. 91 and 95 of Ohio Department of Taxation 2012 Annual Report, http://www.tax.ohio.gov/portals/0/communications/publications/annual_reports/2012_annual_report/2012_AR_internet.pdf

[3e] Depreciation schedules for utility assets found in Form U-EL by Ohio Department of Taxation: http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2014/PU_EL_2014.xls

[4a] Berks county tax rates available at: http://www.co.berks.pa.us/Dept/Assessment/Documents/2014%20co%20twp%20%202013%20sch%20tax%20rate.pdf

[4b] Real properties assessed at 100% according to conversations with Chief Tax Assessor of Berks County.

[4c] - [4e]: According to *Pennsylvania Legislator's Municipal Deskbook*, only real estate tax assessed by local governments in Pennsylvania

[5a] Current real property rate in Fauquier County available at: http://www.fauquiercounty.gov/government/departments/commrev/index.cfm?action=rates. Reviewed property tax rates for Fairfax and Dinwiddie counties, which range from 0.8 – 1.1%.

[5b], [5d] Assessment ratio provided by Virginia State Corporation Commission Principal Utility Appraiser in March 2014.

[5c] Code of Virginia (§ 58.1-2606., Line C) states generating equipment shall not exceed the real estate rate applicable in the respective localities; we assume personal property tax rate equal to the real property tax rate in [5a].

[5e] Received depreciation for electric companies from Virginia State Corporation Commission by Principal Utility Appraiser via email; confirmed that depreciation ceiling of 90% and floor of 25% apply to personal property.

4. Working Capital

We estimated the cost of maintaining working capital requirements for the reference CT and CC by first estimating the working capital requirements (calculated as accounts receivable minus accounts payable) as a percent of gross profit for 3 merchant generation companies: NRG, Calpine, and Dynegy. The weighted average working capital requirement among these companies is 5.59% of gross profits.[22] Translated to the plant level, we estimate that the working capital requirement is approximately 0.7% of overnight costs in the first operating year (increasing with inflation thereafter). In the capital cost estimates, we do not include the working capital requirements but instead the cost of maintaining the working capital requirement based on the borrowing rate for short-term debt for BB rated companies 0.96%.[23]

5. Firm Transportation Service Contract in Southwest MAAC

The gas pipeline serving the part of SWMAAC we identified for the reference plants is the Dominion Cove Point (DCP) pipeline. We understand from shippers that they have had trouble obtaining gas on the DCP pipeline. Availability of interruptible service has been unreliable and inflexible with the pipeline being fully subscribed and also unable to absorb substantial swings in usage within a day. To at least partially address this problem, we assume new CC plants will sign up for firm transportation service on DCP. We assume that the new CT will not acquire firm service due to the relatively few hours such a plant is expected to operate.

To estimate the costs of acquiring firm transportation service on the DCP pipeline for a plant coming online in 2018, we assume the same transportation reservation rate on DCP as that filed for the proposed Dominion Cove LNG export project. That rate is $5.5260 per dekatherm per month for 2017,[24] which we escalate to 2018 dollars, resulting in a rate of $5.6503 per dekatherm.[25] We assume that the CC will reserve sufficient gas service to support baseload operation (without supplemental duct firing) as summarized in Table 22. This results in a $6.5 million annual cost, adding $11,100/MW-year to the CONE for CCs in SWMAAC.

Flexible, no-notice, non-ratable firm service would cost even more, but we do not have a basis for estimating such costs. Instead, we assume energy margin calculations would have to account for limited flexibility of gas service from the DCP (see Section III.B of the 2014 VRR Report).

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22 Gross profits are revenues minus cost of goods sold, including variable and fixed operation and maintenance costs.

23 15-day average 3-month bond yield as of February 14, 2014, BFV USD Composite (BB), from Bloomberg.

24 Application for Authority to Construct, Modify, and Operate Facilities Used for the Export of Natural Gas under Section 3 of the Natural Gas Act and Abbreviated Application for a Certificate of Public Convenience and Necessity under Section 7 of the Natural Gas Act, Volume 1 of III, Public, before the Federal Energy Regulatory Commission, in the matter of Dominion Cove Point LNG, LP, Cove Point Liquefaction Project, filed April 1, 2013. Docket No. CP13-___-000. Available at http://newsinteractive.post-gazette.com/20130401-5045(28233263).pdf.

25 This does not include variable charges, which should not be included in CONE but should be accounted for in estimating energy margins to calculate Net CONE.

Table 22
Estimated Cost of Procuring Firm Gas Service on DCP Pipeline

Component	Units	Gas CC
Plant Characteristics		
Summer ICAP (w/o duct-firing)	*(MW)*	591
Summer Heatrate at Baseload (HHV)	*(Btu/kWh)*	6,811
Gas Consumption at Baseload		
Maximum Hourly	*(MMBtu/hr)*	4,023
Maximum Daily	*(MMBtu/hr)*	96,563
Firm Gas Reservations		
Cost of Firm Gas Capacity per Month	*(2018$/Dth)*	$5.6503
Total Firm Gas Capacity Reservation	*(Dth)*	96,600
Total Cost of Firm Gas Reservations	***(2018$)***	**$6,550,000**
	(2018$/MW-year)	$11,100

Sources and Notes:
See footnote 24.
1 dekatherm (Dth) is equivalent to 1 MMBtu.

B. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they inform the E&AS revenue offset calculations performed annually by PJM. We provide an explanation of the costs here to clearly differentiate which O&M costs are considered fixed and which are variable.

- **Major Maintenance:** Over the long-term operating life of CT and CC plants, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based major maintenance, the average variable O&M cost (in dollars per megawatt-hour, or $/MWh) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the plant capacity in megawatts. For starts-based major maintenance, the average variable O&M cost ($/factored start, per turbine) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored starts between overhauls.
- **Other Variable O&M**: Other variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. These items are always expressed in $/MWh, regardless of whether the maintenance component is hours-based or starts-based.

C. ESCALATION TO 2018

We escalated the components of the O&M cost estimates from 2014 to 2018 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 18) have been also used to escalate the O&M costs. The assumed real escalation rate for labor is 1.5% per year, while those for other O&M costs are 0.4%.

D. SUMMARY OF O&M COSTS

Based on the technical specifications for the reference CT and CC in Section II and the O&M estimates in this section, a summary of the fixed and variable O&M for an online date of June 1, 2018 is shown below in Table 23 and Table 24.

Table 23
Summary of O&M Costs for CT Reference Technology

	CONE Area				
O&M Costs	**1** **EMAAC** *396 MW*	**2** **SWMAAC** *393 MW*	**3** **Rest of RTO** *385 MW*	**4** **WMAAC** *383 MW*	**5** **Dominion** *391 MW*
Fixed O&M (2018$ million)					
LTSA	$0.3	$0.3	$0.3	$0.3	$0.2
Labor	$1.5	$1.1	$1.2	$1.1	$1.0
Consumables	$0.2	$0.2	$0.2	$0.2	$0.2
Maintenance and Minor Repairs	$0.4	$0.4	$0.4	$0.4	$0.4
Administrative and General	$0.2	$0.2	$0.2	$0.2	$0.2
Asset Management	$0.4	$0.4	$0.4	$0.4	$0.4
Property Taxes	$0.4	$5.3	$2.5	$0.4	$3.1
Insurance	$2.4	$2.2	$2.1	$2.2	$2.2
Firm Gas Contract	$0.0	$0.0	$0.0	$0.0	$0.0
Working Capital	$0.0	$0.0	$0.0	$0.0	$0.0
Total Fixed O&M (2018$ million)	**$5.9**	**$10.1**	**$7.2**	**$5.2**	**$7.7**
Levelized Fixed O&M (2018$/MW-yr)	**$15,000**	**$25,600**	**$18,800**	**$13,700**	**$19,600**
Variable O&M (2018$/MWh)					
Major Maintenance - Hours Based	2.40	2.39	2.39	2.39	2.36
Consumables, Waste Disposal, Other VOM	1.89	1.89	1.89	1.89	1.89
Total Variable O&M (2018$/MWh)	**4.29**	**4.27**	**4.27**	**4.27**	**4.25**

Table 24
Summary of O&M Costs for CC Reference Technology

O&M Costs	1 EMAAC *595 MW*	2 SWMAAC *591 MW*	3 Rest of RTO *578 MW*	4 WMAAC *576 MW*	5 Dominion *587 MW*
	CONE Area				
Fixed O&M (2018$ million)					
LTSA	$0.3	$0.3	$0.3	$0.3	$0.2
Labor	$4.6	$3.3	$3.6	$3.5	$3.0
Consumables	$0.3	$0.3	$0.3	$0.3	$0.3
Maintenance and Minor Repairs	$4.7	$4.1	$4.3	$4.2	$4.0
Administrative and General	$0.4	$0.3	$0.3	$0.3	$0.3
Asset Management	$0.7	$0.6	$0.7	$0.6	$0.6
Property Taxes	$1.4	$9.9	$5.5	$1.5	$6.0
Insurance	$4.8	$4.2	$4.3	$4.4	$4.2
Firm Gas Contract	$0.0	$6.6	$0.0	$0.0	$0.0
Working Capital	$0.1	$0.0	$0.0	$0.1	$0.0
Total Fixed O&M (2018$ million)	**$17.4**	**$29.7**	**$19.2**	**$15.1**	**$18.7**
Levelized Fixed O&M (2018$/MW-yr)	**$26,000**	**$44,800**	**$29,500**	**$23,300**	**$28,300**
Variable O&M (2018$/MWh)					
Major Maintenance - Hours Based	1.49	1.45	1.47	1.47	1.45
Consumables, Waste Disposal, Other VOM	1.14	1.14	1.14	1.14	1.14
Total Variable O&M (2018$/MWh)	**2.63**	**2.60**	**2.61**	**2.61**	**2.60**

V. Financial Assumptions

A. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[26] The appropriate ATWACC reflects the systemic financial market risks of the project's future cash flows as a merchant generating plant participating in the PJM markets. As a merchant project, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts and other hedges in place. This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

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26 The "after-tax weighted-average cost of capital" (ATWACC) is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

To estimate the cost of capital for such a project, we reviewed a broad range of reference points. As there is significant uncertainty in any single cost of capital estimate, we reviewed all of the available reference points and selected a level that is reasonable considering the wide range of values. The reference points that we are using include updated estimates for publicly-traded merchant generation companies (NRG, Calpine, and Dynegy), additional sources from previous analysis by Brattle, fairness opinions for merchant generation divestitures, and analyst estimates.[27] Supplementing our analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours. We derived each of the reference points as follows, with results summarized in Table 25.

- **Publicly Traded Companies**: we derived ATWACC estimates using the following standard techniques.
  - *Return on Equity:* We estimate the return on equity (ROE) using the Capital Asset Pricing Model (CAPM). The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta."[28] We calculated a risk-free rate of 3.4% using a 15-day average of 30-year U.S. treasuries as of February 2014.[29] We estimated the expected risk premium of the market to be 6.5% based on the long-term average of values provided by Credit Suisse and Ibbotson.[30] The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index. The resulting return on equity ranges from 7.1–11.9% for the companies included in the analysis, as shown in Table 25.[31]
  - *Cost of Debt*: We estimate the cost of debt (COD) by compiling the unsecured senior credit ratings for each merchant generation company and examining the bond yields associated with those credit ratings. In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments, with "AAA" being the highest rating and "D" being the lowest. Calpine and Dynegy's credit

[27] We do not include private equity investors in our sample because their cost of equity cannot be observed in market data. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses face lower risks and lower cost of capital than merchant generation.

[28] Brealy, Richard, Stuart C. Myers, and Franklin Allen (2011). *Principles of Corporate Finance*. New York: McGraw-Hill/Irwin.

[29] Bloomberg, Bloomberg Professional Service (2014). Data downloaded February 21, 2014. (Bloomberg, 2014). Risk free rate calculated based on 30 year U.S. bond yields.

[30] The Ibbotson market risk premium is 6.7% and the Credit Suisse market risk premium is 6.2%. Ibbotson (2013), *SBBI 2013 Valuation Yearbook*, Chicago: Morningstar, 2013. Dimson, Elroy, Paul Marsh, and Mike Stauton (2013). *Credit Suisse Global Investment Returns Sourcebook 2013,* Zurich: Credit Suisse Research Institute, February 2013.

[31] Dynegy financial characteristics are currently significantly different from Calpine and NRG as it is in the final stages of emerging from bankruptcy. However, we believe that it still can provide a useful reference point for estimating the cost of capital for a merchant generator.

ratings are "B," with an associated cost of debt of 8.7%, while NRG's is "BB" with a 7.5% cost of debt.[32]

- *Debt/Equity Ratio*: We estimate the five-year average debt/equity ratio for each merchant generation company using company 10-Ks for the debt value and Bloomberg for the market value of equity.

- **April 2011 Brattle Estimates** were calculated using a similar approach and have been adjusted downward by 0.9 percentage points for the current analysis based on the difference in the risk-free rate between April 2011 (4.3%) and February 2014 (3.4%).
- **The other reference points** come from publicly available values used by financial advisors and analysts in valuations associated with mergers and divestitures. For example, the financial advisors for the acquisition of GenOn by NRG used discount rates of 7.0–8.5% for NRG and 8.5–9.5% for GenOn in their discounted cash flow analyses associated with the merger. While there are no details provided on how these ranges were developed, we find these values provide useful reference points for estimating the cost of capital. The values in Table 25 have been adjusted upward by 0.7 percentage points due to the change in risk-free rates since the original estimates were developed by the financial analysts in 2012.

32 Data downloaded from Bloomberg in 2014.

Table 25
Summary of Cost of Capital Reference Points and Recommended ATWACC

	Brattle Updated ATWACC Estimates						Prior Estimates Adjusted to Feb 2014 Risk-Free Rate			
Company	S&P Credit Rating	Equity Beta	Return on Equity	Cost of Debt	Debt/ Equity Ratio	After Tax WACC	July 2012 Financial Advisor Estimates for NRG-GenOn Merger	Apr 2011 Brattle Estimates	2011 Analyst Estimates	2011 Fairness Opinions
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Publicly Traded Companies										
Calpine	B	1.29	11.9%	8.7%	61/39	7.8%		6.7%	6.6%	
NRG	BB	1.04	10.4%	7.5%	73/27	6.1%	7.7 - 9.2%	6.3%	6.2%	
Dynegy	B	0.49	7.1%	8.7%	42/58	6.1%		7.4%	7.1 - 11.1%	
Acquired Companies (previously traded)										
GenOn Energy							9.2 - 10.2%	10.3%	7.6 - 9.6%	
Mirant								8.0%	7.6 - 8.6%	
Merchant Generation Divestitures										
FirstEnergy Merchant Generation										7.1 - 8.1%
Allgheny Merchant Generation										7.1 - 7.6%
Duke's Merchant Generation										7.3 - 8.3%
Recommendation			**13.8%**	**7.0%**	**60/40**			**8.0%**		

Sources and notes:
[1]: Bloomberg, 2014.
[2]: Brattle analysis.
[3] = Assumed risk-free rate (3.40%) + assumed market risk premium (6.50%) × [2].
[4]: Bloomberg, 2014.
[5]: Market structure calculated by Brattle using company 10-Ks for debt value and Bloomberg for market value of equity.
[6] = (% Debt) × [4] × (1 – [6]) + (% Equity) × [3]
[7] – [10]: 2011 and 2012 estimates have been adjusted based on changes in the risk-free rate. The risk-free rates were 4.3% in April 2011, 2.7% in July 2012, and 3.4% February 2014. (Bloomberg, 2014)
[7]: NRG Energy Inc. and GenOn Energy, *Joint Proxy Statement/Prospectus for Special Meeting of Stockholders to be Held on Friday, November 9, 2012*, October 5, 2012, pp. 63, 70, and 75.
[8] – [10]: 2011 PJM CONE Study contains original analysis for [8] and citations to original sources for [9] and [10].

Based on this set of reference points and our assumption of merchant entry risk that exceeds the average risk of the publicly-traded generation companies, we believe an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE. That value is above the cost of capital of Calpine and NRG, both of which have some long-term contracts and hedges in place, and it is near the mid-point of the range of the additional reference points.

Although the specific assumptions on capital structure, ROE, and COD corresponding to our ATWACC have almost no impact on the CONE calculation, we do need to assume specific values in order to quantify interest during construction and depreciable capital costs. We assumed a capital structure of 60/40 debt-equity ratio to reflect typical projects' capital structures and their associated ROE and COD. For a representative COD of 7.0% and a 60/40 debt-to-equity capital structure, the ATWACC of 8.0% translates to an ROE of 13.8%, as shown in Table 25. Note that the ATWACC applied to the five CONE Areas varies very slightly with applicable state income tax rates, as discussed in the following section.

B. OTHER FINANCIAL ASSUMPTIONS

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, and interest during construction.

Inflation rates affect our CONE estimates by forming the basis for projected increases in various FOM cost components over time. We also use the inflation rate as the cost escalation rate in our level-real CONE estimate. We estimated future twenty-year inflation rates based on bond market data, Federal Reserve estimates, and consensus U.S. economic projections. The implied inflation rate over twenty years from treasury yields is 2.2%, and the Cleveland Federal Reserve estimate of inflation expectations is 1.9% over twenty years.[33] The most forward looking forecast in the Blue Chip Economic Indicators report is 2.3%.[34] Based on these sources, we assumed for the Net CONE calculations an average long-term inflation rate of 2.25%.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal and state tax rates. The marginal federal corporate income tax rate for 2013 is 35%.[35] The state tax rates assumed for each CONE Area are shown in Table 26. Virginia's lower rate slightly reduces Dominion's CONE, although ATWACC there increases from 8.0% to 8.1% because the debt tax shield is less valuable.

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33 As stated on the Cleveland Federal Reserve website, "The Cleveland Fed's estimate of inflation expectations is based on a model that combines information from a number of sources to address the shortcomings of other, commonly used measures, such as the "break-even" rate derived from Treasury inflation protected securities (TIPS) or survey-based estimates. The Cleveland Fed model can produce estimates for many time horizons, and it isolates not only inflation expectations, but several other interesting variables, such as the real interest rate and the inflation risk premium." Federal Reserve Bank of Cleveland (2013), *Cleveland Fed Estimates of Inflation Expectations*, accessed July 16, 2013. Available at http://www.clevelandfed.org/research/data/inflation_expectations/.

34 Blue Chip Economic Indicators (2013), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers, March 2013. We used the consensus ten-year average consumer price index (CPI) for all urban consumers.

35 Internal Revenue Service (2013), *2012 Instructions for Form 1120, U.S. Corporation Income Tax Return*, January 25, 2013. Available at http://www.irs.gov/pub/irs-pdf/i1120.pdf.

Table 26
State Corporate Income Tax Rates

CONE Area	Representative State	Corporate Income Tax Rate
1 Eastern MAAC	New Jersey	9.00%
2 Southwest MAAC	Maryland	8.25%
3 Rest of RTO	Pennsylvania	9.99%
4 Western MAAC	Pennsylvania	9.99%
5 Dominion	Virginia	6.00%

Sources and notes:
State tax rates retrieved from www.taxfoundation.org

We calculated depreciation based on the current federal tax code, which allows generating companies to use the Modified Accelerated Cost Recovery System (MACRS) of 20 years for a CC plant and 15 years for a CT plant.[36]

To calculate the annual value of depreciation, the "depreciable costs" (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 60% debt and 7.0% COD.

VI.Summary of CONE Estimates

Translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how net revenues are received over time to recover capital and annual fixed costs. "Level-nominal" cost recovery assumes that net revenues will be constant in nominal terms (*i.e.*, decreasing in real dollars, inflation adjusted terms) over the 20-year economic life of the plant. A "level-real" cost recovery path starts lower then increases at the rate of inflation (*i.e.*, constant in real dollar terms).[37] As discussed in the 2014 VRR Report, we recommend that PJM adopt the level-real value as it is more consistent with our expected trajectory of operating margins from future capacity and net E&AS revenues. All descriptions below refer to level-nominal values to facilitate consistent comparison with parameters PJM is currently using.

[36] Internal Revenue Service (2013), *Publication 946, How to Depreciate Property,* February 15, 2013. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

[37] Both cost recovery paths (level-real and level-nominal) are calculated such that the NPV of the project is zero over the 20-year economic life.

Table 27 and Table 28 show summaries of our capital costs, annual fixed costs, and levelized CONE estimates for the CT and CC reference plants for the 2018/19 delivery year. For comparison, the tables include the most recent 2017/18 PJM administrative CONE parameters and the results of the 2011 PJM CONE Study for the 2015/16 auction, with both escalated to a 2018/19 delivery year at 3% per year to reflect estimated historical escalation rates for generation.[38]

For the CT, our CONE estimates differ by CONE Area due to differences in plant configuration and performance assumptions, differences in labor rates, differences in property tax regulations, and other locational differences in capital and fixed O&M costs. EMAAC and SWMAAC have the highest CONE estimates at $150,000/MW-year and $148,400/MW-year, respectively, due to significantly higher labor costs in EMAAC and high property taxes in SWMAAC that are based on all property, not just land and buildings, as in some other areas. WMAAC and Dominion have the next highest CONE values of $143,500/MW-year and $141,200/MW-year, respectively. The Rest of RTO Area has the lowest CONE values of $138,000/MW-year due to the lack of dual-fuel capability and lower labor costs.

38 The 3% escalation rate is based on a component-weighted average of the escalation rates in Table 1818.

Table 27
Recommended CONE for CT Plants in 2018/2019

		CONE Area				
		1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs						
Overnight	*($m)*	$400	$373	$348	$372	$364
Installed	*($m)*	$420	$391	$364	$390	$382
First Year FOM	*($m/yr)*	$6	$10	$7	$5	$8
Net Summer ICAP	***(MW)***	**396**	**393**	**385**	**383**	**391**
Unitized Costs						
Overnight	*($/kW)*	$1,012	$948	$903	$971	$931
Installed	*($/kW)*	$1,061	$994	$947	$1,018	$977
Levelized FOM	*($/MW-yr)*	$15,000	$25,600	$18,800	$13,700	$19,600
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$127,300**	**$126,000**	**$117,100**	**$121,800**	**$119,900**
Level-Nominal	***($/MW-yr)***	**$150,000**	**$148,400**	**$138,000**	**$143,500**	**$141,200**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$161,600	$150,700	$148,000	$155,200	$132,400
Brattle 2015/16 Estimate*	*($/MW-yr)*	$145,700	$134,400	$134,200	$141,400	$120,600
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	($11,600)	($2,300)	($10,000)	($11,700)	$8,800
Brattle 2015/16 Estimate	*($/MW-yr)*	$4,300	$14,000	$3,800	$2,000	$20,600
PJM 2017/18 Parameter	*(%)*	-8%	-2%	-7%	-8%	6%
Brattle 2015/16 Estimate	*(%)*	3%	9%	3%	1%	15%

Sources and Notes:

Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Table 27 compares these CONE estimates to two reference points: PJM's current parameters for the 2017/18 capacity auction and Brattle's prior estimates for the 2015/16 delivery year from its 2011 PJM CONE Study. To produce a meaningful comparison, we show these reference points escalated to 2018 at 3% per year. As shown, our estimates are similar to the Brattle 2015/16 values, except in SWMAAC and Dominion where updated property tax calculations and labor costs contribute to increasing the CONE values by 9% and 15%, respectively. Our estimates in those CONE Areas are closer to the PJM 2017/18 parameters (which are higher than the Brattle 2015/16 values largely because they were escalated from prior settlement values using a Handy-Whitman index that has risen significantly faster than actual plant costs, as noted in our 2014 VRR Report). In the other CONE Areas (EMAAC, Rest of RTO, and WMAAC), our estimates are lower than the 2017/18 parameters. Overall, our estimates are within -8% to +6% of PJM's current parameters, depending on the Area.

Comparing the current CT CONE estimates to the Brattle 2015/16 estimates, the CT CONE values are either approximately equal in EMAAC, Rest of RTO and WMAAC or higher by 9% in SWMAAC and higher by 15% in Dominion. The SWMAAC and Dominion values are higher for several reasons. First, we assumed higher labor rates, based on the prevailing wages in those Areas, which include a mix of union and non-union labor. Second, increased property tax estimates that now consider taxes on personal property (*i.e.*, the plant equipment) in accordance with state tax laws in both of these regions also lead to higher CONE estimates. Third, the assumed addition of an SCR on the Dominion CT increased the CONE estimates there. Other components of the estimate also changed there and in all the CONE Areas, but with increases in some categories offsetting decreases in others. Assumptions that increased CONE included higher EPC contract costs (mostly due to labor costs), EPC contingency costs, and owner's project development costs. On the other hand, a lower ATWACC and lower plant O&M estimates reduced CONE.

For the CC, EMAAC has the highest CONE estimates at $203,900/MW-year due to labor costs that are higher than the rest of PJM. SWMAAC and WMAAC have the next highest CC CONE at $197,200/MW-year and $190,900/MW-year, respectively. The CONE Areas with the lowest values are Rest of RTO (due to the lack of dual fuel) at $188,100/MW-yr and Dominion (as it has the lowest labor costs) at $182,400/MW-year.

Table 28
Recommended CONE for CC Plants in 2018/2019

		CONE Area				
		1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs						
Overnight	*($m)*	$808	$707	$709	$737	$708
Installed	*($m)*	$885	$775	$777	$808	$776
First Year FOM	*($m/yr)*	$17	$30	$19	$15	$19
Net Summer ICAP	***(MW)***	**668**	**664**	**651**	**649**	**660**
Unitized Costs						
Overnight	*($/kW)*	$1,210	$1,065	$1,089	$1,137	$1,073
Installed	*($/kW)*	$1,326	$1,168	$1,193	$1,245	$1,176
Levelized FOM	*($/MW-yr)*	$26,000	$44,800	$29,500	$23,300	$28,300
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$173,100**	**$167,400**	**$159,700**	**$162,000**	**$154,800**
Level-Nominal	***($/MW-yr)***	**$203,900**	**$197,200**	**$188,100**	**$190,900**	**$182,400**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$199,900	$176,300	$192,900	$191,800	$170,100
Brattle 2015/16 Estimate*	*($/MW-yr)*	$183,700	$161,000	$177,100	$176,700	$157,000
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	$4,100	$20,900	($4,700)	($900)	$12,200
Brattle 2015/16 Estimate	*($/MW-yr)*	$20,300	$36,200	$11,100	$14,200	$25,400
PJM 2017/18 Parameter	*(%)*	2%	11%	-3%	0%	7%
Brattle 2015/16 Estimate	*(%)*	10%	18%	6%	7%	14%

Sources and Notes:

Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Compared to the Brattle 2015/16 values, the current CC CONE estimates are higher across all CONE Areas due to higher estimated costs of EPC contingency, owner's project development costs, and plant O&M costs. While the EPC contract cost increased in all cases, the SWMAAC and Dominion values increased more due to higher estimated labor costs than in the previous analysis, as we found the prevailing wages in those regions include both union and non-union labor, whereas the previous analysis assumed strictly non-union labor.

The updated CC CONE values have increased over the prior estimates more than the CT CONE values have, leading to a higher cost premium for CCs of $41,000-54,000/MW-year compared to $27,000-43,000/MW-year in our prior study. The most significant driver for the greater CC CONE increase is the relative difference in plant O&M costs estimated by S&L compared to the previous analysis. As noted earlier in this report, the CT fixed O&M in the current analysis is less than the 2011 value, with a larger fraction treated as variable costs; however, the fixed CC plant O&M is greater than the previous value. Combined, this difference explains approximately two-thirds of the increase in the CC premium. The rest of the difference is explained primarily by higher labor rates, and contingency and project development factors than in the prior study, which add more dollars to the cost of the more capital-intensive CC than the CT. In the Dominion CONE Area, the addition of the SCR to the CT largely offsets these differences.

At PJM's request, we are also providing estimates for the Rest of RTO CONE Area with dual-fuel capabilities, as shown in Table 29. Adding dual-fuel capabilities to the plant specifications increases the level-nominal value of the CT CONE by $9,500/MW-year and the CC CONE by $5,600/MW-year.

Table 29
Rest of RTO CONE Estimates for Different Fuel Configurations

		Gas CT		Gas CC	
Rest of RTO		**Single Fuel**	**Dual Fuel**	**Single Fuel**	**Dual Fuel**
Gross Costs					
Overnight	*($m)*	$348	$373	$709	$733
Installed	*($m)*	$364	$391	$777	$802
First Year FOM	*($m/yr)*	$7	$8	$19	$20
Net Summer ICAP	***(MW)***	**385**	**385**	**651**	**651**
Unitized Costs					
Overnight	*($/kW)*	$903	$969	$1,089	$1,125
Installed	*($/kW)*	$947	$1,016	$1,193	$1,232
Levelized FOM	*($/MW-yr)*	$18,800	$19,700	$29,500	$29,900
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**
Levelized Gross CONE					
Level-Real	***($/MW-yr)***	**$117,100**	**$125,100**	**$159,700**	**$164,400**
Level-Nominal	***($/MW-yr)***	**$138,000**	**$147,500**	**$188,100**	**$193,700**

List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
BACT	Best Available Control Technology
BLS	Bureau of Labor Statistics
CAPM	Capital Asset Pricing Model
CC	Combined Cycle
CO	Carbon Monoxide
COD	Cost of Debt
CONE	Cost of New Entry
CPV	Competitive Power Ventures
CT	Combustion Turbine
DCP	Dominion Cove Point
DCR	Demand Curve Reset
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation and Maintenance
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
ISO	Independent System Operator
LDA	Locational Deliverability Area
LAER	Lowest Achievable Emissions Rate
LTSA	Long-Term Service Agreement
m	Million
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System

MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hours
NNSR	Non-Attainment New Source Review
NNY	Non-New York
NO_x	Nitrogen Oxides
NSR	New Source Review
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFE	Owner-Furnished Equipment
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, LLC
PSD	Prevention of Significant Deterioration
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
ULSD	Ultra-Lower Sulfur Diesel
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

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THE Brattle GROUP

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	Docket No. ER14-___

AFFIDAVIT

STATE OF Massachusetts)
)
CITY OF Lincoln, Ma)

DR. SAMUEL A. NEWELL, being duly sworn, deposes and states: that the Affidavit of Dr. Samuel A. Newell on behalf of PJM Interconnection, L.L.C. was prepared by him or under his direct supervision, that the statements contained therein and the Attachments attached thereto are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

DR. SAMUEL A. NEWELL

Subscribed and sworn to before me this 3rd day of October, 2014.

Notary Public
My Commission Expires: December 19, 2019

MARINA KVITMAN
Notary Public
Commonwealth of Massachusetts
My Commission Expires
December 19, 2019