April 8, 2014

Scott Baker, Facilitator
Janell Fabiano, Secretary
PJM Capacity Senior Task Force
955 Jefferson Avenue
Norristown, PA 19403

Re: MOPR Unit Specific Review Development Process

Dear Scott & Janell:

This letter presents data to support the Maryland Public Service Commission's (MD PSC) recommended principles for the "Unit Specific Review" Exception ("USR") to PJM's 'Minimum Offer Price Rule' ("MOPR") in its "Reliability Pricing Mechanism" ("RPM"). Attachment A provides an updated statement of MD PSC's position.[1]

I understand that you will incorporate the MD PSC's updated position into Column B of the Task Force's current Solutions Matrix and that I will be given an opportunity to explain it at the upcoming April 11 Task Force meeting. Attachment B also proposes language which the MD PSC urges be incorporated into PJM's Manuals, language that summarizes the central market principles under which this Exception to the MOPR should be permitted to operate.

In its May 2, 2013 Order adjudicating PJM's most recent major rewrite of its MOPR, FERC stated:

> "[W]e find that PJM's proposed changes [to the MOPR] are not just and reasonable standing alone, and therefore we accept the filing subject to PJM's retention of its unit-specific review process . . . . [T]here may be resources that have lower competitive costs than the default offer floor, and these resources should have the opportunity to demonstrate their competitive entry costs. . . . We encourage PJM and its stakeholders to consider . . . whether the unit-specific review process would be more effective if PJM requires the use of modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective individual cost advantages." [2]

The MD PSC believes that markets should permit individual sellers and buyers to adopt and act upon their own, individual expectations as to future electricity price and service conditions, and thereby to establish on the basis of those expectations their required compensation or payment level for participating in that market. In aggregate, these seller and buyer expectations then act to establish market prices. End users are benefitted by such markets in that sellers with lower costs or cost expectations cause price competition lowering prices for buyers.

The solution proposal presented by PJM (i.e. column A of the CSTF Solution Matrix), as

[1] MD PSC's position was first presented to PJM in the summer of 2013.
[2] See PJM Interconnection, LLC, 143 FERC ¶ 61,090 at ¶s 141 to 144 (2013).

the result of its mandating specific cost levels for many of the inputs to the RPM's capacity price determination, violates this central market principle. Indeed, the PJM proposal seeks to establish an administratively determined and unnecessarily inflated floor for capacity market prices, under the guise of adopting "modeling assumptions" – as suggested by FERC. "Modeling assumptions", however, must be limited to methodological issues, i.e. such as whether historic or future revenues can be used as the basis for the MOPR cost estimate, not (as PJM proposes) what those specific numerical estimates must be. Solution Package A does not limit itself to such methodological matters, but rather seeks to impose, based upon PJM/IMM administrative determinations, the level, amongst others, of capital costs, depreciation costs, revenue offsets and other costs or offsets that a seller may suggest in seeking participation of its generation project in the PJM capacity market. Indeed, as the result of this administrative cost prescription, the MD PSC understands that a very substantial percentage of total capacity cost priced in the RPM market will hereafter be established by PJM administrative determination rather than by developer proposed costs. FERC's objective in its 2013 Order that developers with unique lower costs be permitted to bid those costs into the BRA will be frustrated by this PJM proposal, and the protections sought to be maintained by FERC for end user and State pricing concerns will have been effectively eliminated.

Also, as previously stated in its July 2013 Letter and in oral statements to the Task Force, the MD PSC strongly disagrees with certain of the cost levels being administratively imposed under the PJM proposal. Most of these disagreements are clearly stated in Attachment A, and the reasons underlying them have been previously stated orally or in the MD PSC's July 2013 letter. However, due to its large pricing effect, the paragraph below opposing the adoption of "nominal levelized" costing for fixed costs is restated here:.[3]

> "[The MD PSC strongly opposes the use of Nominal Levelized cost recovery treatment both as inappropriate to a truncated one year cost evaluation (i.e. that of the BRA) and as inconsistent with the use of a one or three year revenue offset estimate. As described in the Brattle Report, Nominal Levelized costing assumes that investment and other fixed costs are recovered in equal installments over the life of major, capital intensive equipment, such as generation equipment, rather than with increasing payments over the equipment's life reflecting annual inflation. As Brattle explains, this advances expected inflation recovery into the early years of project life. [4] While either Nominal Levelized or Real Levelized, in inflation corrected terms, produces the same result over the unit's entire life, that is not true where the only value used for cost recovery is a first year value as in the case of the BRA. For this reason, Brattle recommends adoption of Real Levelized, stating that Nominal Levelized will result in cost over-recovery and over-procurement of generation resources under the RPM. [5]

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[3] Indeed, FERC has stated that nominal levelized costing should not be imposed on generation developers who do not choose to use it in the USR process: "We agree with PJM that, while the nominal cost recovery method is appropriate for the MOPR screen, requiring that cost recovery method during the unit-specific review process is unnecessary. In making a case to the IMM, PJM, or the Commission, parties should have the opportunity to present a reasonable business case based on their individualized facts and circumstances . . . " PJM Power Providers Group v. PJM Interconnection, LLC, 137 FERC ¶ 61,145, at ¶ 74 (2011).

[4] The Brattle Group, Second Perf. Assessment of PJM's Reliability Pricing Model at pp. 81-86 (August 26, 2011).

[5] Brattle Report at pp. 81 & 85. "[W]e believe setting CONE equal to level-nominal costs will overstate annualized

The MD PSC also notes that its research into the practices approved by FERC with regard to other RTOs indicate that PJM's USR proposals are not uniformly consistent with those accepted practices. For example, ISO-NE has MOPR standards which permit a generation developer to present its actual or estimated project specific costs as its "MOPR" rather than the RTO's administratively determined cost level as proposed by PJM and supported by IMM.[6] For example, in a February 2013 Order, FERC described the ISO-NE MOPR process as follows (ISO-NE Order Paragraphs 13, 14 & 17):

> ISO-NE submits proposed tariff revisions establishing resource-type specific benchmark prices which it refers to as "offer review trigger prices" . . ., because a new resource may offer capacity in the FCA at prices equal to or above the relevant offer review trigger price with no cost review by the Internal Market Monitor (IMM) while IMM review is "triggered" by offer prices below the offer review trigger price.
>
> Trigger prices form a screen: offers at or above the trigger price are accepted into the FCA with no further review; offers below the trigger price may nevertheless be accepted into the FCA if they are justified with the IMM during the unit-specific review process. NEPGA and NRG argue that ISO-NE has wrongly employed a weighted average cost of capital based on the assumption that a project's output is under contract, with the result that generation trigger prices are improperly below the merchant cost of new entry. . . . [W]e are satisfied by ISO-NE's rationalization that, in the case of New England, use of trigger prices at the low end of the spectrum strikes a reasonable balance by not subjecting clearly competitive offers to IMM evaluation . . . ."

ISO-NE's MOPR process thus "includes the option of unit-specific review for resources wishing to offer below their benchmark price," and employing generation developer proposed costs rather than costs administratively prescribed by the RTO. (ISO-NE Order, Paragraph 7) ISO-NE's "benchmark pricing" developed as the MOPR minimum price is but a trigger to further review of actual Generator supported costs, not a mandatory minimum based on RTO administratively determined costs which sell offers can not fall below. Also, specific cost assumptions employed by ISO-NE as of the date of FERC's February 2013 Order often differ from and are lower than those proposed by PJM/IMM, including particularly the assumed life of natural gas-fired CT and CC equipment (30 years with a 10% salvage value), the year one

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costs over time and, as a result, could lead to over-procurement under RPM . . . ." Indeed, as respects defining minimum bid thresholds under MOPR, Brattle states an even stronger position, stating that: "We believe level-real annualization is more consistent with market fundamentals and competitive bidding behavior. As a result, we recommend against retaining the level-nominal approach for CC and CT offer thresholds under the MOPR."

[6] See, e.g., Re ISO New England Inc., 142 FERC ¶ 61,107 (2013); Re NYISO, 143 FERC ¶ 61,217 (2013); Shaw Consul. Int'l. Inc., Benchmark Price Model Inputs – Final Rep. (2012); NYISO, Buyer Side Mitigation – Narrative and Num. Example (2012). FERC has recently confirmed this ISO-NE approach in Re ISO New England Inc., 146 FERC ¶ 61,084, at ¶s 50-55 (February 11, 2014), in which it stated: "ISO-NE states that . . . it aimed to develop ORTPs [Offer Review Trigger Prices] based on the "low end of competitive entrants, and assumed the existence of a power purchase agreement for non-capacity revenues, which would lower a resource's risk and therefore its cost of capital." FERC affirmed this practice, stating that "consistent with our finding in the February 2013 Order, we find that ISO-NE appropriately based its cost of capital on that of a resource with a power purchase agreement."

capacity price output from the model (i.e. apparently real not nominal levelized), and the assumption in capital cost determination that the "benchmark" plant being priced has a twenty year power purchase agreement (i.e. negotiated at arm's length). [7] Further, as respects capital costs, FERC has stated the importance of PJM being able "to recognize the lower financing costs of sellers that are especially creditworthy or that have negotiated contracts that have enabled them to secure favorable credit terms" as a part of the USR process, and has rejected the adoption of hypothetical capital structures such as now proposed by PJM that would prohibit consideration of such developer actual costs.[8]

Finally, as repeatedly stated in CSTF Meetings, the MD PSC is very concerned that the PJM/IMM proposed USR minimum cost standard suggests a cost for new electric generation that will well exceed that in non-market jurisdictions, i.e. jurisdictions which continue to utilize traditional regulation in incenting the operation and expansion of generation equipment. The MD PSC has noted that B rated merchant debt and equity costs are, based on available capital cost indexes significantly higher than A or BBB rated costs common in traditional regulated jurisdictions, and that the PJM/IMM proposed life and associated depreciation cost of merchant generation is roughly double the cost of these items in a regulated jurisdiction. Regulated jurisdictions, moreover, do not employ nominal levelized costing, which Brattle suggests is 10% or more costly in early years than real level costing. After consideration of all of these costing differences, the MD PSC is concerned that any new merchant generation that PJM/IMM expects will be developed based on its capacity market revenues and Minimum Offer Price Rule will be at least 30% more costly than new generation that can be developed in traditional regulated states. If these concerns are borne out by actual events in coming years, States such as Maryland which are required to rely soley upon PJM markets for the development of their electric generation could be placed at a very severe economic disadvantage.

Sincerely yours,

Walter R. Hall II

Walter R. Hall II
Senior Energy Markets Advisor
Maryland Public Service Commission

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[7] See Shaw Consultants Report at pp. 11-12 & 17; ISO-NE Order, Paragraphs 17 & 44-45.

[8] See PJM Interconection, L.L.C., 137 FERC ¶ 61,145 at ¶ 249 (2011). As FERC stated: ""Hess states that it strongly supports the use of a reference unit financing structure (capital structure, cost of debt and return of equity) rather than allowing project developers to put forth their individual financing structures. The Commission rejects Hess' proposal to require PJM to adopt a reference unit financing structure as part of its unit-specific review process. Such a requirement would not allow PJM to recognize the lower financing costs of sellers that are especially creditworthy or that have negotiated contracts that have enabled them to secure favorable credit terms."

Attachment A
Capacity Senior Task Force
MOPR Unit Specific Review Process
Solutions Matrix

	B (MD PSC)
Line 1a – Use of Project Specific Information	Entirely Base on Demonstrated Project Specific Information if requested by the Developer. Review for Reasonableness.
Line 2a – Detail Required	Level of detail appropriate to the specific item. Credibility of Project Specific Information may be shown upon the basis of actual accounting costs, procurement or similar cost records, estimates/forecasts from expert and authoritative sources, or costs/revenues achieved by other similar projects.
Line 2a(i) – inflation rate	Developer sponsored inflation rate based upon documented study or expert forecast.
Line 2a(ii) – Debt:Equity Ratio	Developer sponsored consistent with claimed inflation rate/capital costs demonstrated as realistic. All reasonable parameters affecting capital structure and cost rates presented by Developer that may reduce experienced capital costs shall be accepted, such as a strong balance sheet, presence of a power purchase agreement, high debt equity ratings, etc.
Line 2a(iii) – Cost of Debt	Developer sponsored consistent with claimed inflation rate/capital costs demonstrated as realistic.
Line 2a(iv) – Cost of Equity	Developer sponsored consistent with claimed inflation rate/capital costs demonstrated as realistic.
Line 2a(v) – Asset Life (Economic Life)	Developer sponsored study based upon reasonable expectation up to 40 years or more if proposed by developer.
Line 2a(vi) - Term & Levelization Approach to	Developer sponsored. Allow Level-Real

Net Revenue	matched with expected in service date or initial three year average. See Brattle Second Triennial Review Report at pp. 81-6.
Line 2b – Identity and Support Sunk Costs (Unit Specific Exception)	Allow deduction of sunk costs where permitted by FERC precedent and as requested by Developer.
Line 2c – Residual Value (Unit Specific Exception)	See item 2a(v) above. Allow based on documented, credible study as sponsored by Developer.
Line 2d – Officer Certification (Unit Specific Exception)	Officer Certification Required
Line 2e – Tax Rates (See Tab 2a for more detail)**(?)**	Developer sponsored tax rates including those documented to provide cost advantages.
Line 2f - Physical Plant Costs **(?)**	Same as PJM where requested by Developer.
Line 3a – Energy Market Revenues	Accept standardized forward looking methodology (3 year average preferred) but Developer allowed to present/support unit specific revenue estimates.
Line 3b – Operational Characteristics & Dispatch	Accept PJM adoption of Project specific values
Line 3c – # of Years of forward Net Revenues	Developer sponsored 1 or 3 year forecast that best reflects future "normal" revenues
Line 3d – Fuel and Emission Allowance Costs	Accept standardized forward looking methodology but Developer allowed to present/support unit specific cost estimates.
Line 3e – Variable O & M Costs	Developer supported estimates/documented variable O & M Costs
Line 3f – Notification to Market Participants regarding assumptions to be used in the Unit Specific Process	Developer advised of ability to propose and document cost/revenue/other assumptions, of limited standardization requirements and PJM adopted CONE values.
Line 3g – Sell Offer Permitted (Unit Specific	**[Do not understand what is requested]**

Exception]

Line 4a – Include seller competitive advantages	Reflect all seller competitive advantages
Line 4b – Business Model	Reflect all business model advantages
Line 4c to 4f – Financial condition, Tax Status, Access to Capital, Other Conditions	Reflect all seller competitive advantages
Line 4g – Irregular or Anomalous Advantages	This concept is not sufficiently defined and should be rejected as granting PJM/IMM unlimited and improper discretion. The objective of a market is to permit consumers to benefit from lower costs not resulting from unlawful, predatory behavior whether irregular, anomalous, enacted into the tax code or available from another source.
Line 5 – Notification	**[Do not understand what is requested]**

Attachment B
Suggested PJM Manual Language to Implement
Unit Specific Review Exception

The MD PSC reads FERC's Order as requiring that the USR procedure constitute a process through which generation developers may demonstrate that their proposed RPM BRA Sell Offer reasonably reflects their anticipated and known cost levels for the specific unit they are developing, and further that neither "common modeling" or other assumptions should be permitted to prevent them from making that demonstration. To assure that FERC's objective is met, the MD PSC proposes that the following language stating this objective be included in PJM Manuals describing the USR procedure:

> "The objective of this Unit Specific Review Exception is to permit a generation developer to demonstrate that its Sell Offer is economically reasonable when compared to the actual and anticipated costs and revenues expected to be obtained from the Unit being developed. While PJM and the IMM may establish "Common Modeling Assumptions" for use in simplifying and presenting a USR Exception request, these assumptions shall not prevent a developer from presenting its Unit's anticipated and actual cost data, as well as its willingness to forego higher cost recovery if it so proposes, in support of its Sell Offer. Moreover, in implementing the Unit Specific Review Exception, all demonstrated cost advantages and reductions associated with the Unit under development shall be recognized in establishing its minimum Sell Offer."

We suggest that notification of this proposed Statement be referenced in your Options Matrix as item 1a under the title USR Objective and the designation "Permit demonstration of Unit actual and anticipated costs and revenues as basis for Sell Offer".

As a second matter requiring specific Manual language, we think it important that the PJM Manuals contain a statement of the extent and character of documentation or support for a Unit's proffered actual or anticipated costs and revenues that will be accepted as establishing actual or anticipated costs and revenue. The MD PSC suggests that the following Manual language would be appropriate:

> "Actual and anticipated costs and revenues may be shown upon the basis of actual accounting records, estimates provided PJM/IMM from expert and authoritative sources, costs or revenues achieved by other similar and similarly situated projects and similar such sources."