Preliminary Questions for the PJM TEAC meeting, October 31, 2023. (version 1.0).

Submitted by the Maryland Office of People's Counsel ("OPC").

Questions are keyed to the identified presentations posted to the TEAC website for review during the October 31, 2023 meeting of the PJM TEAC.

OPC requests that PJM post these questions (as well as those from other stakeholders) to the PJM website along with PJM's written answers thereto to allow for public and transparent review of PJM's review, analysis and decisions and of the transmission projects subject to PJM's TEAC review implicated by OPC's questions. OPC asks that these questions and comments be formally considered and included in PJM's further review and deliberations regarding the projects under consideration by PJM and the TEAC.

In an instance where a response to a question impinges on limitations or restrictions that PJM has in providing a response, please identify the question (or question sub-part) and the basis for the limitation or restriction. If the information is CEII restricted, please identify the scope of the restriction and OPC and its consultants will submit a CEII disclosure request to allow for disclosure. Subject to the foregoing, if PJM has developed or prepared written analysis or documentation supporting or related to its response (and not already publicly disclosed through the TEAC meeting materials' filings), OPC requests that such written documentation be provided.

OPC reserves the right to propound additional questions to PJM. OPC requests timely responses to these questions to allow for informed participation prior to and during the second read of the TEAC project selections; or, failing that, an extension of the period for the submittal of questions by the public, PJM responses and disclosure and public comment, prior to the second read.

The Brandon Shores and Wagner units' deactivations, the solutions to address the resulting grid violations and the 2022 RTEP Window 3 solutions selections entail very significant policy/technical decisions, comprising $5-6 billion in transmission related capital expenditures, construction of major infrastructure facilities across Maryland (generally) and Virginia (for the 2022 RTEP Window 3 projects), and, in the case of the 2022 RTEP Window 3 projects, facilities to address unprecedented increases in electric load (equivalent to the existing load of the metropolitan area of Baltimore) in a very focused area. OPC's questions and the requested disclosures of PJM are fully justified in this extraordinary context.

1. **Generator Deactivation Notification Update.**

“PJM’s preliminary assessment indicates reliability violations with Wagner’s requested deactivation. The assessment assumed Brandon Shores continues to be in operation.” Presentation, p. 4.

1.1. Has Talen (the owner of both the Brandon Shores and Wagner power plants) agreed to an RMR arrangement for the operation of the Brandon Shores power plant through 2028? What is the status of that discussion?

1.2. Is PJM aware that Talen’s CEO stated last week the following:

"Given our ample free cash flow and limited need for go-forward growth capex, we believe implementing a shareholder return program is an appropriate part of our overall capital allocation plan," said Mac McFarland, President, and Chief Executive Officer. "This share repurchase program demonstrates our commitment to disciplined capital allocation, including prioritizing the return of capital to our shareholders." Talen News Release, Oct. 23, 2023.

1.3. If Talen is refusing to agree to (an) RMR arrangement(s) for its Maryland plants due to asserted deficient financial resources to cover possible capex required to keep the Brandon Shores and/or Wagner power plants in operation beyond the noticed deactivation dates, how is that squared with Talen’s CEO’s statement about “limited need for go-forward growth capex”?

1.4. What is PJM’s procedure for Talen’s response to a request for a RMR from PJM if PJM deems continued operation of one or more of the Wagner units are required? When will the resource owner disclose which option it will elect for compensation under the PJM tariff, Part V, secs. 115 – 119. for operation under an RMR arrangement, assuming the resource owner agrees to such an arrangement? What is the “avoidable” cost for the Brandon Shores and Wagner units, respectively, under the PJM Tariff, Part V, sec. 115 (and, if not yet determined, what is the procedure for establishing such cost)? Full and early disclosure of the costs of the RMRs for these units are of significant importance to Maryland ratepayers.

1.5. Will the grid solutions, if deemed required for the Wagner units’ deactivation, be treated as an “immediate need” project and, if so, how will PJM justify and document this?

1.6. What level of reliability violations arise due to sub-groups of the Wagner units retiring? Which violations are due to thermal overloads, and which are voltage stability related?

Wagner (as covered by the deactivation units) consists of 4 units (total 841 MW):

Unit	MWs of capacity	Fuel	Age of Unit
Wagner 1	126	Natural gas	67
Wagner 3	305	Coal	64
Wagner 4	397	Oil	51
Wagner CT 1	13	Diesel	56

1.7. Are the reliability violations (preliminarily determined) independent of and arising after the RTEP Window 3 solutions and/or the Brandon Shores deactivation grid solutions, respectively, are constructed and in service?

1.8. Assuming the Brandon Shores and Wagner units are deactivated, are there circumstances where 1.15 CETO>CETL for additional nested LDAs (e.g., SWMAAC, MAAC)? When and how will this be determined? Do and when do those LDAs result in a locational price adder for the (newly) identified constrained LDAs for the next (or succeeding BRAs)?

1.9. What is the RPM capacity accreditation for each of the Wagner units assuming they were to participate in the PJM RPM, as reformed under the currently pending CIFP package before FERC?

1.10. What is the current "headroom" for interconnection of new generation resources at points of interconnection ("POIs") located within the BGE LDA? What will it be following the completion of the grid solutions for the Brandon Shores deactivation and the pending Wagner deactivation, respectively? What would be the effect on headroom for interconnection to the POIs within the BGE LDA if the CIRs associated with the Brandon Shores and Wagner units were available and treated as headroom in the BGE LDA?

1.11. PJM also studying the impacts of Wagner without Brandon Shores online?

1.12. Will PJM be revisiting the transmission solution proposed to address the Brandon Shores' retirement to see if it could be adjusted to also facilitate Wagner's retirement?

1.13. How many CIRs does Talen have arising from the Brandon Shores and Wagner plants, respectively? What is Talen doing regarding the usage of the CIRs associated with the Brandon Shores and Wagner plants? Has it transferred them (or filed to transfer them) to other projects in the interconnection queue for utilization following the deactivation of its existing plants? If so, which projects, what capacity will be connected and utilizing what power source?

1.14. Do the Wagner units currently provide reactive supply and voltage control service under PJM Tariff, Schedule 2?

2. Reliability Analysis Update (2022 RTEP Window 3 projects selection).

2.1. What state and local permits will be required for each of the selected project segments [p. 71]?

2.2. Has PJM identified a back-up or default project segment to the selected project segments, if any one of them is rejected or deemed not feasible in the future for some reason (e.g., due to failure to acquire a regulatory permit)? When and how will PJM determine in the future that a project segment in the award group is not feasible and how will it then adjust its project selection?

2.3. How was (is) the modeling of the 2022 RTEP Window 3 "need" sequenced with the "need" triggered by the Brandon Shores and Wagner retirements? Were the Brandon Shores retirement grid solutions assumed completed in the baseline for the RTEP window, so that the incremental need for 2022 RTEP Window 3 assumed (and benefitted from) completion of the Brandon Shores retirement grid solutions? What is the justification for the sequencing of the modeling? What are its implications for cost allocation to load of the selected transmission projects?

2.4. Did PJM do (or does PJM contemplate doing) an analysis of an optimization of the aggregate costs of the Brandon Shores grid solutions, the pending Wagner deactivation grid solutions and the 2022 RTEP Window 3 selected projects? If such an analysis was done, what were the results?

2.5. What amount of "headroom" (and in which location) for entry of new non-wires resources will be created by the 2022 RTEP window 3 selected projects? Are there transmission upgrade costs previously identified for a resource in PJM's interconnection queue (in a feasibility study, system impact study or interconnection service agreement) which will be duplicative of the costs of the 2022 RTEP Window 3 selected projects? If so, in what amounts and for which points of interconnection?

2.6. What amount of new non-wire resources were assumed to be operating and over what periods in the 2022 RTEP Window 3 analysis? What were the criteria for their inclusion or exclusion?

2.7. The 2022 RTEP Window 3 selected transmission project components show completion dates out to the end of 2030. How does that comport and match the 2027, 2028 load cases used to model the "need" for the projects? There is a reference to "layering" or creating some measure of incremental capacity to address future load growth? How much additional transfer capacity (or other latent ability to meet reliability violations) in excess of the load cases was incorporated into/exists in the selected projects?

2.8. What is the cost allocation for recovery in rates to load serving entities (LSEs) resulting from the selected projects? When will this analysis be done and reported publicly?

2.9. p. 71 shows capex ("cost") by the selected project component, project proponent and per an independent review conducted by PJM. There are significant variances in certain cases between the project proponent's cost and the independent cost. Which selected project segment(s) was/were accompanied by cost control or cost cap commitments by the project proponent(s), if any, and how defined? [Specifically, the NextEra Woodside-Aspen 500 kV line, substation and STATCOM, project 853, p. 71 – project proponent cost - $632MM vs. PJM "independent cost" of $1.078B].

2.10. Is PJM's load forecast used to plan the 2022 RTEP Window 3 selected projects, consistent with the Virginia State Corporation Commission's (SCC's) approved forecasts for load growth within the Dominion service territory, resulting from Dominion's integrated resource plan (IRP) filings? Please explain any differences, if any, between the two forecasts.