UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Delaware Public Service Commission, and Maryland Public Service Commission Complainants, v. PJM Interconnection, L.L.C., and Certain Transmission Owners Designated Under Attachment A to the Consolidated Transmission Owners Agreement, Rate Schedule FERC No. 42 Respondents.	)))))))))))))	Docket No. EL15-_____-000

COMPLAINT OF THE
DELAWARE PUBLIC SERVICE COMMISSION AND
MARYLAND PUBLIC SERVICE COMMISSION

Pursuant to Section 206 of the Federal Power Act ("FPA"),[1] and Rule 206 of the Rules of Practice and Procedure[2] of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the Delaware Public Service Commission ("Delaware PSC") and the Maryland Public Service Commission ("Maryland PSC") (collectively, "Complainants") respectfully tender for filing this Complaint against PJM Interconnection, L.L.C. ("PJM"), and certain Transmission Owners designated under Attachment A to the Consolidated Transmission Owners Agreement ("CTOA"), Rate Schedule FERC No. 42, that have voting rights over cost allocation and rate

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[1] 16 U.S.C. §§ 824e, 824v, 825e (2012).
[2] 18 C.F.R. § 385.206 (2014).

design, as listed in Section IV, *infra*.[3] Complainants request that the Commission find that PJM's use of a "solution-based DFAX" to allocate the costs of the "Artificial Island" Regional Transmission Expansion Plan ("RTEP") Project ("Artificial Island Project" or "Project") is unjust, unreasonable, and unduly discriminatory and preferential.[4] As evidenced below, PJM's sole reliance on the solution-based DFAX methodology for allocating Artificial Island Project costs results in a grossly disproportionate financial impact to customers within the Delmarva transmission zone when compared with the limited benefits to consumers in that zone. The Commission should therefore direct PJM to modify the PJM OATT, and any relevant provisions of the PJM Operating Agreement, to ensure that the allocation of costs for the Artificial Island Project is consistent with Commission and appellate court precedent and consistent with principles of cost causation. The modification should be filed with the Commission in a compliance filing that is due no later than 90 days after the issuance of a Commission order in this proceeding.

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[3] *See* Consolidated Transmission Owners Agreement, Rate Schedule FERC No. 42, Attachment A, *available at* http://www.pjm.com/~/media/documents/agreements/toa.ashx. Pursuant to Section 7.3.1 of the CTOA, the PJM TOs retain the "unilateral" right to file pursuant to Section 205 of the FPA "for changes in or relating to . . . any provisions in the PJM [Open Access Transmission Tariff ("Tariff")] governing the recovery of transmission-related costs incurred by the TOs." However, pursuant to Section 8.5.3 of the CTOA, "Zero Revenue Requirement Parties" are not entitled to vote on cost recovery. Section 1.32 defines Zero Revenue Requirement Party as any "Party that is a Transmission Owner solely by virtue of Transmission Facilities used to provide transmission services within the PJM Region under the PJM Tariff for which it does not have a cost-of-service rate for such services set forth in Schedules 7 and 8 and Attachment H of the PJM Tariff." The Transmission Owners that are named Respondents to this complaint are listed in Section IV of this Complaint.

[4] PJM's cost allocation for the Artificial Island Project is "preliminary" by virtue of the operation of certain provisions of Schedule 12 of the PJM Open Access Transmission Tariff ("OATT" or "Tariff"). Under Schedule 12, PJM is required to make “a preliminary cost responsibility determination for each Required Transmission Enhancement subject to this section (b)(iii) of Schedule 12 at the time such Required Transmission Enhancement is included in the Regional Transmission Expansion Plan.” Tariff, Schedule 12, § (b)(iii)(H). PJM's cost responsibility determination remains in effect until the project has gone into service; in the interim, the determination applies to any allowed recovery of Construction Work in Progress. *Id.* § (b)(iii)(H)(1). Once a project goes into service, the cost responsibility assignment is revised and updated each year that the facility remains in service. *Id.* § (b)(iii)(H)(2). That said, there is no indication that PJM's "preliminary" determination will change as and after the Artificial Island Project goes into service.

I. EXECUTIVE SUMMARY

1. The Artificial Island Project is a PJM RTEP project that involves the construction of a new 230 kV transmission line under the Delaware River, and construction and installation of certain other facilities, to address certain system stability and related generation operation issues in the Artificial Island area in southern New Jersey. PJM's Board of Managers ("PJM Board") has adopted the use of the solution-based DFAX methodology to allocate the costs of the Artificial Island Project.[5]

2. The Commission approved the use of solution-based DFAX for purposes of cost allocation of certain PJM-approved transmission projects as part of a comprehensive cost allocation proposal that the PJM Transmission Owners filed to comply with Order No. 1000.[6] The attached Affidavit of John J. Marczewski ("Marczewski Affidavit") describes the solution-based DFAX methodology and how it is applied pursuant to the PJM Tariff.[7]

3. PJM's application of solution-based DFAX to the Artificial Island Project results in the Delmarva Zone, which includes load located within the states of Delaware and Maryland, being assigned approximately 90 percent of the costs of the Artificial Island Project. Other analyses conducted by PJM demonstrate that the Delmarva Zone will receive only 10 percent of the benefits associated with the Project. The result is even more egregious given that the generation issues to be resolved by the Artificial Island Project are not located in the Delmarva Zone. Such disproportionate alignment of benefits and costs is unjust, unreasonable, and wholly inconsistent with cost-causation principles and legal precedent requiring the allocation of transmission project costs to be "roughly commensurate" with the benefits of the project. As

[5] *See* Letter From PJM Board Regarding Artificial Island(attached hereto as Appendix 1), *available at* http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx.
[6] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 411 (2013) ("March 2013 Order").
[7] *See* Affidavit of John J. Marczewski (attached hereto as Appendix 7) at PP 12-14.

explained below, the "roughly commensurate" standard controls over other objectives that the Commission sought to achieve – such as *ex ante* clarity and uniform approaches to cost allocation – in Order No. 1000.

4. Because PJM's reliance on the solution-based DFAX methodology to assign costs of the Artificial Island Project is unjust, unreasonable, and unduly discriminatory and preferential, when judged against the controlling "roughly commensurate" standard, Complainants respectfully request this Commission to require PJM to modify the OATT, and any applicable provisions of the Operating Agreement, to ensure that the allocation of costs for the Artificial Island Project is consistent with Commission and appellate court precedent and consistent with well-established principles of cost causation.

II. THE ARTIFICIAL ISLAND PROJECT

5. The Artificial Island area is located in southern New Jersey and is the area in which Salem Units 1 and 2 (collectively, "Salem") [8]and Hope Creek Unit 1 ("Hope Creek")[9] nuclear generating units are located. These generating units are operated by PSEG Nuclear LLC. The Artificial Island Operating Guide, including a special protection scheme, was developed in 1987 to address stability limitations and minimum megavolt-ampere reactive ("MVAR") output requirements at the Salem/Hope Creek generation complex.[10] Absent the development of the Operating Guide, generation output from this complex would need to be reduced under certain conditions to address dynamic and transient stability limitations.[11] Effectively, the Operating

[8] PSEG Nuclear LLC owns 57% of Salem 1 and 2, Exelon Corporation owns the remaining 43%. *See* Salem Nuclear Generating Station Facts, *available at* https://www.pseg.com/family/power/nuclear/pdf/salem_factsheet.pdf.
[9] PSEG Nuclear LLC owns 100% of the Hope Creek 1 nuclear generating plant. *See* Hope Creek Nuclear Generating Station Facts, *available at* https://www.pseg.com/family/power/nuclear/pdf/hope_creek_factsheet.pdf .
[10] *See* Artificial Island Project Recommendation White Paper (attached hereto as Appendix 2) at 10, *available at* http://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx ("White Paper").
[11] *See id.*

Guide replaced the development of additional transmission system outlets that would have been needed for the generation to export power to other areas on the PJM grid.

6. The Operating Guide itself dictates how the generation at the Salem/Hope Creek complex must be operated to permit maximum generation output. Use of the Operating Guide to allow maximum generation output requires PJM to adjust other components of the transmission system to accommodate the MVAR and voltage requirements dictated by the Operating Guide. PJM's attempts to accommodate the 'requirements' of the Operating Guide have made it difficult for PJM to maintain system voltages within limits. Accordingly, the Operating Guide itself has now become a limiting constraint.

7. In light of these operational issues, PJM opened an RTEP process window on April 29, 2013 seeking proposals to improve operational performance on bulk electric system facilities in the Artificial Island area. PJM specified that solution proposals must improve stability margins, reduce Artificial Island MVAR output requirements, and address high voltage reliability issues. Specifically, the request sought proposals to eliminate Artificial Island Operating Guide complexity regarding stability limitations and minimum unit MVAR output requirements, as well as to address previously identified high voltage reliability issues. PJM asked that proposals achieve the following objectives:

A. Generate maximum power (3,818 MW total) from all Artificial Island units without a minimum MVAR requirement. Full maximum power must be maintained under both baseline and all N-1 500 kV line outage conditions in the Artificial Island area. Voltages must be maintained within established operating limits and stable for all NERC Category B and C contingencies. N-1-1 contingencies do not need to be applied in addition to the N-1 500 kV outage condition in the Artificial Island area.

B. Ensure maximum Artificial Island MW output is not affected by the simultaneous outage of power system stabilizers of Salem Unit

2 and Hope Creek. The Salem Unit 1 power system stabilizer is assumed to be on for all scenarios.

C. Reduce operational complexity.

D. Improve Artificial Island stability.

E. Maintain PJM System Operating Limits ("SOLs").[12]

8. When the Artificial Island window closed on June 28, 2013, PJM began evaluating the 26 proposals along three dimensions – system performance, constructability, and cost. Initial analytical studies tested proposals in terms of transient stability, voltage, and thermal and short-circuit performance against established North American Electric Reliability Corporation ("NERC") and regional reliability planning criteria. Ultimately, PJM identified all or part of five proposals that would be the basis for further consideration. Two of the five proposals included construction of a new 500 kV transmission line; one of the five proposals included no new construction of transmission lines; and two of the five proposals included construction of a new 230 kV transmission line.

9. By letter dated July 29, 2015, the PJM Board announced its approval of a new 230 kV transmission line to be constructed under the Delaware River from Salem to a new substation in Delaware that would tap the existing Red Lion-Carranza and Red Lion-Cedar Creek 230 kV lines (the "LS Power project").[13] Associated substation work at Salem, including existing 500 kV substation expansion and installation of a new 500/230 kV auto-transformer, would be designated to Public Service Electric and Gas Company ("PSE&G"). Associated work on the 230 kV right-of-way in Delaware to tap into existing 230 kV lines would be completed by Pepco Holdings, Inc. ("PHI"). Together, the new 230 kV transmission line, the substation work at Salem, and the right-of-way work comprise the Artificial Island Project.

[12] *Id.* at 9.
[13] *See* Appendix 1.

10. During the Transmission Expansion Advisory Committee ("TEAC") process, PJM Staff applied the solution-based DFAX provisions of the PJM Tariff to generate potential cost allocations for the various projects. After PJM Staff recommended the LS Power project to the PJM Board on April 28, 2015, the Complainants focused their efforts on determining the cost allocation that would result from acceptance of the LS Power project for the Artificial Island Project. The White Paper that formed the basis for the PJM Board's July 29 acceptance of the LS Power project states the following concerning cost allocation:

> PJM is responsible for determining RTEP upgrade cost allocation, seeking PJM Board approval and filing those allocation percentages with the FERC under the terms of PJM's Operating Agreement, Schedule 6, and Open Access Transmission Tariff, Schedule 12. To that end, PJM has developed preliminary cost responsibility percentages – as shown in Appendix 1 − for Artificial Island solution project elements whose costs will be allocated to multiple transmission zones. PJM notes that the aggregate total amount of the project to be assigned to the Delmarva transmission zone is $246.42 million, 89.46 percent of the total $275.45 million cost estimate. The remaining $29.03 million would be assigned to other transmission zones based on load ratio shares.[14]

11. During the time between the PJM Staff recommendation to the PJM Board, and the PJM Board's July 29, 2015 announcement of its acceptance of the LS Power project, the Delaware PSC, the Governor of Delaware on behalf of the State of Delaware, the Delaware Division of the Public Advocate, Delaware-based industrial customers, and the Maryland Public Service Commission, among others, voiced their concerns to the PJM Board regarding the proposed allocation of Artificial Island Project costs if the LS Power proposal were to be accepted.[15] In its cover letter announcing its acceptance of the LS Power project, the PJM Board acknowledged the significant concerns regarding the solution-based DFAX cost allocation for the Artificial Island Project:

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[14] Appendix 2 at 38.

[15] *See, e.g.*, Letters to the PJM Board on Artificial Island Cost Allocation (attached hereto as Appendix 3), a*vailable at* http://pjm.com/about-pjm/who-we-are/pjm-board/public-disclosures.aspx.

> The Board also recognizes the valid concerns raised by Governor Markell, the Delaware Public Service Commission, the Maryland Public Service Commission and others regarding the allocation of costs associated with this project. PJM must follow its Tariff. And with regard to the cost allocation provisions applicable to this project, PJM also must respect legal precedent in the Atlantic City case allocating specific rate filing responsibilities between PJM and its transmission owners. Nonetheless, we recognize that several parties have appropriately questioned the specific allocation in this case. Accordingly, PJM will continue to provide technical analysis and information to affected stakeholders in order to help FERC with its ruling on this particular cost allocation and its cost allocation rules in general.[16]

As the Letter from the PJM Board suggests, PJM appears to understand that the cost allocation for the Artificial Island Project raises significant and legitimate concerns, but perceives that Commission-accepted OATT provisions prevent PJM from applying an alternative approach for allocating the costs of the Artificial Island Project.

III. SERVICE AND COMMUNICATIONS

12. All correspondence and communications to the Complaint in this docket should be addressed to the following individuals, whose names should be entered on the official service list maintained by the Secretary in connection with these proceedings:

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[16] *See* Appendix 1.

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IV. DESCRIPTION OF THE PARTIES

13. The Delaware PSC has authorized the filing of this Complaint. The Delaware PSC is a state utility regulatory agency responsible for ensuring safe, reliable, and reasonably priced utility services for Delaware consumers, including those customers located in the Delaware portion of the Delmarva Zone.

14. The Maryland PSC has also authorized the filing of this Complaint. The Maryland PSC is a state utility regulatory agency responsible for ensuring safe, reliable, and reasonably priced utility services for Maryland consumers, including those customers located in the Maryland portion of the Delmarva Zone.

15. PJM is a "public utility" as that term is defined in Section 201(b)(2)(e) of the FPA. PJM is a duly authorized regional transmission organization ("RTO") approved by the Commission pursuant to 18 C.F.R. § 35.34. PJM's footprint includes Delaware and Maryland. PJM operates day-ahead and real-time energy markets, provides transmission services, and oversees an ancillary services and capacity market, all pursuant to its Tariff.

16. The PJM Transmission Owners are, generally, "those entities that own or lease (with rights, equivalent to ownership) Transmission Facilities" within the PJM region and are signatories to the CTOA. The PJM Transmission Owners that are named as Respondents to this Complaint are those PJM Transmission Owners with voting rights over cost allocation and rate

design. To the best of the Complainants' knowledge, information, and belief, those PJM Transmission Owners with such voting rights are:

- Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power
- American Electric Power Service Corporation on behalf of its operating companies: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company
- Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.
- Dayton Power and Light Company
- Virginia Electric and Power Company (Dominion Virginia Power)
- Public Service Electric and Gas Company
- PECO Energy Company
- PPL Electric Utilities Corporation
- Baltimore Gas and Electric Company
- Jersey Central Power & Light Company
- Metropolitan Edison Company
- Pennsylvania Electric Company
- Potomac Electric Power Company
- Atlantic City Electric Company
- Delmarva Power & Light Company
- UGI Utilities, Inc.
- Allegheny Electric Cooperative, Inc.
- Old Dominion Electric Cooperative
- Rockland Electric Company
- Duquesne Light Company
- Trans-Allegheny Interstate Line Company
- American Transmission Systems, Incorporated
- Duke Energy Ohio, Inc.
- Duke Energy Kentucky, Inc.
- East Kentucky Power Cooperative, Inc.

V. ARGUMENT

A. Solution-Based DFAX, As Applied To the Artificial Island Project, Does Not Produce An Allocation of RTEP Project Costs That Is "Roughly Commensurate" with the Benefits of the Project.

17. The Commission is obligated to ensure that the costs of transmission projects that are allocated to customers are roughly commensurate with the benefits that those customers

receive from such projects.[17] Recent precedent makes clear that the Commission's obligation extends beyond assuming that a proposed cost allocation scheme will result in benefits to the customers charged; rather, the Commission must affirmatively "compar[e] the costs assessed against a party to the burdens imposed or benefits drawn by that party."[18] When the Commission accepted solution-based DFAX as a component of the PJM Transmission Owners' Order No. 1000 compliance filing, the Commission was of the view that power flows across a new transmission facility would reveal, and align with, the benefits associated with that facility. For example, the Commission concluded in its March 13 Order that the solution-based DFAX methodology "evaluates the projected relative use of a new Reliability Project by load in each zone and withdrawals by [merchant transmission facilities] *and through this power flow analysis identifies projected benefits for individual entities in relation to power flows*."[19] In other words, the Commission viewed solution-based DFAX as a means of ensuring an outcome where benefits and costs are roughly commensurate. As demonstrated in this Complaint, however, the assumption underlying the Commission's acceptance of solution-based DFAX has not held true in all instances, and especially does not hold true with respect to the Artificial Island Project.

18. The solution-based DFAX methodology cannot be relied on to allocate costs for the Artificial Island Project to transmission customers in a manner that is roughly commensurate with the benefits that such customers receive from the Project. Using the solution-based DFAX methodology to allocate the costs of the Artificial Island Project, where customers in the Delmarva Zone will be expected to absorb nearly 90 percent of the project costs without any demonstration that these customers will commensurately benefit from the project, does not result

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[17] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470,476 (7th Cir. 2009) ("*ICC I*").
[18] *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004).
[19] March 2013 Order at P 416 (emphasis added).

in an allocation of costs that aligns with the beneficiaries of the project.[20] Notably, PJM's application of the solution-based DFAX cost allocation methodology to the Artificial Island Project is not coupled with any empirical justification (as required by relevant precedent) or other objective basis upon which the Commission could satisfy its duty to ensure that the costs allocated to customers are generally proportionate to the benefits derived by those customers.

19. When reviewing cost allocation methodologies for RTO transmission projects, the United States Court of Appeals for the Seventh Circuit ("7th Circuit") has held that FERC must (1) analyze the costs assessed to customers against the burdens imposed on those customers, and (2) issue an order that includes empirical justification for approving the cost allocation regime.[21] In *ICC I*, the 7th Circuit explained that FERC could not disregard the disparity between the cost allocation under the methodology it approved and the varying benefits of new transmission facilities in different parts of the region.[22] The 7th Circuit held that:

> FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members. "All approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them."[23]

The *ICC I* court further cautioned that, while FERC need not calculate the distribution of benefits with precision, it must, at a minimum, have an "articulable and plausible reason to believe that the benefits [of the new transmission lines] are at least roughly commensurate with [the] utilities' share of total electricity sales."[24]

20. In *ICC II*, the 7th Circuit further clarified that the Commission must "<u>demonstrate</u> – that the benefits [of the new transmission lines] are proportionate to the total electric-power

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[20] *See, e.g.,* Appendix 2 at 38-40.
[21] *See ICC I,* 576 F.3d at 477; *Ill. Commerce Comm'n v. FERC,* 756 F.3d 556, 561 (7th Cir. 2014) ("*ICC II*").
[22] *See ICC I*, 576 F.3d at 476-77.
[23] *Id*. at 476 (quoting *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004)).
[24] *Id.* at 477.

output of each utility . . . ."[25] In doing so, the Commission could not assume that the new transmission lines at issue in that case were essentially for the benefit of the entire grid; rather, the Commission must offer empirical evidence justifying the cost allocation methodology based on the "specific reliability violations" the project is designed to address.[26] The 7th Circuit offered the following analogy to clarify FERC's cost-benefit analysis obligation:

> There are bound to be benefits to the entire grid and therefore to the utilities connected to it, but they are incidental, just as repairing a major pothole in a city would incidentally benefit traffic in the city's suburbs, because some suburbanites commute to the city. So they should pay a share of the cost of repair, but a share proportionate to their use of the street with the pothole rather than proportionate to their population. The incidental-benefits tail mustn't be allowed to wag the primary-benefits dog.[27]

21. The standards articulated in *ICC-I* and *ICC-II* were echoed by the United States Court of Appeals for the District of Columbia Circuit in its opinion upholding the Commission's *ex ante* cost allocation requirements in Order No. 1000:

> The [cost-allocation reforms in Order No. 1000] do not require any particular provider to pay for new facilities or dictate precisely how costs must be allocated. Instead, the Commission requires public utilities to have in place a method or methods for allocating the costs of new transmission facilities "in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs," and for ensuring that costs are not "involuntarily allocated to entities that do not receive benefits."[28]

22. This Complaint demonstrates that the Commission cannot satisfy the obligation to align costs and benefits of the Artificial Island Project based on an application of the solution-based DFAX methodology. The projected cost of the portion of the Artificial Island Project that is 100% subject to the solution-based DFAX cost allocation is $216 million.[29] The Artificial

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[25] *ICC II*, 756 F.3d at 561 (emphasis added).
[26] *See id.* at 564.
[27] *Id*.
[28] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 85 (D.C. Cir. 2014) (citing *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011)).
[29] *See* Appendix 2 at 39-40.

Island Project includes an additional $59.45 million in project work, on 500 kV facilities, that is allocated in part on a load-ratio share basis and in remaining part on a solution-based DFAX basis. In addition to the $216 million previously referenced, PJM determined that 51.21% of the $59.45 million in 500 kV facility costs will also be allocated to the Delmarva Zone, which results in $30.44 million in additional costs being allocated to the Delmarva Zone.[30] In total, customers in the Delmarva Zone will be expected to absorb $246.43 million of the $275.45 million price tag for the Artificial Island Project. Assuming a conservative 15% carrying charge for these costs, the annual charges to the Delmarva zone would be in the range of $30 million to $37 million.[31] To be clear, the vast majority of the costs expected to be allocated to the Delmarva Zone directly result from the application of the solution-based DFAX methodology.

23. In a study requested by the Delaware PSC, PJM Staff analyzed the benefits accruing to customers, across the PJM footprint, from the Artificial Island Project.[32] PJM Staff's analysis shows that only about 10 percent ($17.04 million) of the total projected annual load payments savings of $169.2 million associated with the Artificial Island Project would accrue to

[30] Indeed, these costs, 50% of which are allocated on the basis of the same solution-based DFAX analysis as the Delaware River crossing transmission line, are for the installation of MVAR generation equipment and for monitoring equipment located on New Jersey transmission lines (including lines stretching from Artificial Island to central and even northern New Jersey) that Complainants understand have minimal or no role in any service and thus provide minimal or no benefit to Delmarva Zone customers. *See* Appendix 2 at 4-7, 36-37. Yet, despite the apparent absence of any benefit from this equipment to customers in the Delmarva Zone, the solution-based DFAX component of this allocation results in the assignment of over 51% of the costs of this equipment to Delmarva Zone customers, in an amount that exceeds $30.44 million. As explained in the PJM White Paper, this equipment is used to provide operational performance benefits under fault conditions to enhance New Jersey transmission line operation that, in the great majority of instances as understood by Complainants, does not provide any direct benefits to Delmarva end-users. *See id*. Notably, while Complainants are challenging the solution-based DFAX component of the cost allocation for these facilities, Complainants are not challenging the load ratio share allocation of 50% of the costs of this equipment.

[31] *See* Appendix 3 at 33 (Delaware Division of the Public Advocate Letter to PJM Transmission Owners at 2 (Aug. 6, 2015)); *see also id.* at 25 (Old Dominion Electric Cooperative Letter to PJM Board at 2 (July 28, 2015)).

[32] PJM compared the locational marginal prices ("LMP") and Load Payments between two scenarios for both a single hour and on an annual basis that could address the stability issues at Artificial Island: (1) the PJM system without the Artificial Island Project and one Salem Unit off-line (addressing the stability issues through generation reduction rather than transmission solutions); and (2) the PJM system with the Artificial Island Project and all Salem Units on-line.

the Delmarva Zone.[33] Another market efficiency analysis conducted by PJM that measured the reduction of unhedgeable congestion shows that the Artificial Island Project would provide, over 15 years, approximately $92 million of congestion cost relief on other transmission facilities.[34] What these benefits analyses reveal is that the application of solution-based DFAX to the Artificial Island Project will lead to the Delmarva Zone being responsible for nearly 90% of total Project costs, while receiving only 10% of the expected benefits of the Project. This gulf of 80 percentage points between costs and benefits demonstrates that PJM's proposed allocation of costs is not "roughly commensurate" with benefits.

24. Aligning benefits and costs is not just important as a matter of law and equity, it is also necessary to avoid perverse incentives to choose projects solely on the basis of avoiding anomalous cost allocation outcomes. As evident from the White Paper and TEAC presentations on Artificial Island, PJM considered more than two dozen proposals to address the system stability and generation operation issues in the Artificial Island area, and many of these proposals involved the construction of 500 kV facilities. Under Schedule 12 of the PJM Tariff, 50% of the costs of such 500 kV facilities would occur on a load ratio share basis, while the remaining 50% of the costs would occur on a solution-based DFAX basis.[35] Zones on the receiving end of the transmission facilities that would be subject to solution-based DFAX cost allocation would have a tendency or incentive to prefer and support a higher-voltage solution (at higher overall cost, and with more significant implementation challenges) than the lower-voltage solution (at lower overall costs, and with less significant implementation challenges), driven solely by the

[33] *See* PJM Market Efficiency Study: Artificial Island Benefits (attached hereto as Appendix 4) at 5, *available at* http://www.pjm.com/~/media/about-pjm/who-we-are/public-disclosures/20150810-de-psc-letter-to-the-transmission-owners-regarding-ai.ashx.
[34] *See* April 28, 2015 TEAC Presentation (attached hereto as Appendix 5) at 37; *see also* May 8, 2014 TEAC Presentation (attached hereto as Appendix 6) at 40.
[35] *See* PJM OATT, Schedule 12 § (b)(ii)(A), *available at* http://pjm.com/media/documents/merged-tariffs/oatt.pdf.

differences in cost allocation approaches. Establishing incentives to favor and support higher-cost and higher-complexity projects over lower-cost and lower-complexity projects is the very antithesis of established cost allocation objectives and principles.

25. Reliance solely on solution-based DFAX to allocate the costs of the Artificial Island Project also ignores the benefits of reduced load flows on the existing PJM 500 and 230 kV grid system that stretches across northern Delaware. The solution-based DFAX essentially ignores the creation of a coincident transmission capacity benefit to all nearby zones by not providing any corresponding cost allocation reduction in light of those benefits. In this instance, the exclusion of recognized system flow-based benefits in the current cost allocation process underscores the reality that the alignment of costs and benefits cannot be considered even roughly commensurate.

B. The Use of Solution-Based DFAX Is Not Appropriate For The Artificial Island Project, Which Is Intended To Address Transmission System Stability and Generation Operation Issues Limiting Exports Out Of An Area.

26. The solution-based DFAX methodology is a relatively new addition to PJM's cost allocation toolbox. Experience with this methodology as a cost allocation tool has proven that, in certain instances, the methodology does not produce results that survive even the most rudimentary cost-benefit analysis for certain types of transmission projects. As discussed in the Marczewski Affidavit, while the solution-based DFAX methodology may be an appropriate cost allocation tool for some types of transmission projects developed to address typical thermal or voltage reliability criteria violations, the methodology does not necessarily lead to just and reasonable results when applied to projects that are developed to address transmission constraints

that are preventing energy flows out of an area, which is the case for the Artificial Island Project.[36]

27. Typically, load growth creates conditions that give rise to violations, or projected violations, of reliability criteria, which in turn require transmission upgrades to eliminate those violations.[37] Eliminating a reliability criteria violation in circumstances where additional generation is need to serve load in a "load pocket" undeniably produces a benefit to that load. PJM's solution-based DFAX methodology allocates costs based on the benefit of such an upgrade to deliver additional generation to load. Thus, fundamental to the solution-based DFAX methodology serving as a reasonable cost allocation tool is an underlying assumption that the initial reliability criteria violation relates to load growth or an inadequacy of the transmission system to meet each load area's requirement from the aggregate of system generation. In contrast, transmission projects such as the Artificial Island Project, which are not related to the adequacy of the transmission system to deliver aggregate system generation into certain load areas, but instead are driven by the inability of the transmission system to deliver output from a specific generation location, are not appropriate candidates for cost allocation under a solution-based DFAX methodology that considers only the flow on the resulting upgrade.

28. Without the use of the Operating Guide, addressing the stability limitation at the Salem/Hope Creek generation complex requires either: (1) a reduction to generator output or, (2) the development of additional transmission outlets. Through its RTEP process, PJM has elected to pursue the latter option. However, under the solution-based DFAX methodology, the zone that PJM selects to be the "receiving" end or the "sink" for any additional transmission outlets for Salem and Hope Creek will necessarily bear the burden of the project costs due to the

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[36] *See* Appendix 7 at P 17.
[37] *See* PJM Manual 14B at 40, *available at* http://www.pjm.com/~/media/documents/manuals/m14b.ashx ("Manual 14B").

directionally-weighted aspect of the solution-based DFAX methodology, whether or not the designated zone receives commensurate benefits from the new generator outlet and whether or not other zones also benefit from the transmission projects.[38]

29. Under the directionally weighted solution-based DFAX methodology, PJM examines net energy flow on a proposed facility that may be part of a solution to a reliability criterion violation, in both directions. PJM next separately determines the zones that use the "solution facility" when flow is in one direction as well as the zones that use the facility when flow is in the opposite direction. Using an 8,760-hour production cost simulation, PJM then assigns a weighting of upgrade cost to these two groups of zones based on the expected percentage of hours that flow on the solution facility that will be in the corresponding direction.[39] Given that the Salem/Hope Creek generation complex represents a 3,818 MW facility that is already under-served with transmission outlets, the 8,760-hour production cost simulation will determine that, for an overwhelming majority of hours, power will flow away from the generation complex and into the zone where the new transmission line terminates. The directionally-weighted aspect of the solution-based DFAX methodology will determine that whichever zone is selected by project developers and ultimately by the PJM Board to be the terminus of the new generator outlet will bear the costs of that generator outlet. This assignment of overwhelming and disproportionate cost responsibility will occur under a solution-based DFAX methodology without regard to the fact that the project is being developed to permit the generation complex to generate at full output rather than having its production otherwise reduced.

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[38] *See* Appendix 7 at P 16.
[39] *See generally* Manual 14B at 41-43.

30. While the zone that is selected to be the end point for the new generator outlet will receive some benefit from the project, it is undeniable that many other zones will also benefit.[40] In the case of the Artificial Island Project, the market efficiency benefits for the Delmarva Zone are projected by PJM to be $17.04 million annually. However, PJM Staff also has reported that PJM-wide market efficiency benefits are $169.2 million annually as a result of the Artificial Island Project, with nearly *all zones* in PJM receiving a benefit.[41] This is not surprising given that the Artificial Island Project is specifically intended to serve as a transmission outlet from the Artificial Island area to the rest of PJM.

31. Thus, under PJM's approach, the solution-based DFAX methodology is assigning nearly 90% of the costs to the Delmarva Zone, while the Delmarva Zone is receiving only 10% of the benefits. Conversely, the solution-based DFAX methodology is assigning only 10% of the costs to other zones in the PJM region, while those areas are receiving nearly 90% of the benefits.[42] Despite the fact that most other zones in PJM will benefit in meaningful and tangible ways from the Artificial Island Project, the solution-based DFAX methodology wholly fails to account for those benefits when it comes to cost allocation. In this instance, the solution-based DFAX outcome stands the "beneficiary pays" principle on its head.[43]

32. While some may argue that PJM's solution-based DFAX methodology is a fairly easy-to-administer, *ex ante* approach for cost allocation determinations, the methodology fails to produce results that can be deemed just, reasonable, and non-discriminatory when it is applied to certain types of transmission projects, including the Artificial Island Project. Where there is a reliability criterion violation caused by inadequate outlets for generation output, the solution-

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[40] *See* Appendix 7 at P 18.
[41] *See* Appendix 4 at 5.
[42] *See* Appendix 7 at P 16..
[43] *See id*. at PP 16-17 (citing the "gross misalignment of costs" with respect to the Artificial Island Project as resulting from the "one-size-fits-all" application of solution-based DFAX).

based DFAX methodology invariably will link cost responsibility with the zone that just happens to be the end-point for the new or expanded generation outlet. The benefits that accrue from the outlet project, however, span a much larger footprint than just the zone that serves as the touch-down point for a new line. In this important regard, the solution-based DFAX methodology fails under certain circumstances (*e.g.*, situations in which individual generator *exports* are at issue) to honor the established beneficiary-pays principles that require that cost allocations match benefits as closely as practicable. The application of the solutions-based DFAX methodology to allocate the costs of the Artificial Island Project is clearly such a circumstance, and results in cost allocations that are unjust, unreasonable, unduly discriminatory and preferential.

33. The commitment of the Commission (and PJM) to sole reliance on PJM's solution-based DFAX for its purported administrative practicality and certainty in cost allocation decision actually results in increased burdens to all stakeholders (including, but not limited to, the Commission, PJM, and customers) because of the obvious failure of the approach to achieve cost allocations that are roughly commensurate with benefits. These increased burdens result from ongoing litigation over solution-based DFAX results that do not square with any reasonable application of the requirement that benefits and costs must be at least "roughly commensurate." Applying solution-based DFAX where it should not be applied, such as in the case of the Artificial Island Project, produces anomalous results that cry out for an alternative remedy.

C. The Commission Has Both the Authority and the Responsibility to Correct this Deficiency in the PJM Tariff, At Least as Concerns the Costs of the Artificial Island Project.

34. The use of a solution-based DFAX methodology to allocate Artificial Island Project costs is unjust, unreasonable, and unduly discriminatory and preferential. Section 206 of the FPA both authorizes and obligates the Commission to "determine the just and reasonable rate

… to be thereafter observed and enforced" upon finding that an existing rate is unjust, unreasonable or unduly discriminatory.[44] Consistent with its statutory duty, the Commission should therefore grant this Complaint and require PJM to amend the Tariff and any applicable Operating Agreement provisions as necessary, to accommodate a project-specific cost allocation methodology for the Artificial Island Project that allocates costs on "roughly commensurate" basis to the benefits conveyed to consumers.

V. REQUESTED RELIEF

35. Based on the evidence presented in this Complaint, the Delaware PSC and the Maryland PSC respectfully request that the Commission, pursuant to Section 206 of the Federal Power Act, find that the use of the solution-based DFAX methodology to allocate costs associated with the Artificial Island Project does not result in an allocation of costs that is roughly commensurate with the benefits of the project and is, therefore, unjust, unreasonable, and unduly discriminatory and preferential.

36. Based upon the foregoing demonstration that PJM's use of the solution-based DFAX methodology to allocate Artificial Island Project costs is unjust, unreasonable, and unduly discriminatory and preferential, the Commission should order PJM to file, within 90 days of the issuance of a Commission order, the necessary changes to the Tariff and, as necessary, the Operating Agreement, to ensure a just and reasonable allocation of Artificial Island Project costs.

VI. COMPLIANCE WITH RULE 206

In the paragraphs below, Complainants demonstrate their compliance with the specific requirements of Rule 206 of the Commission's Rules of Practice and Procedure.

Description of alleged violation and quantifications of impacts – 18 C.F.R. § 385.206(b)(1)-(5).

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[44] *See* 16 U.S.C. § 824(e) (2012).

Complainants have provided, to the extent practical under the circumstances, the information and available documents sought by Rule 206(B)(1)-(5), in Parts I-V of this Complaint.

Other pending proceedings – 18 C.F.R. § 385.206(b)(6).

The specific issues presented herein related to the cost allocation of the Artificial Island Project are not pending in an existing Commission proceeding or a proceeding in any other forum in which the Delaware PSC or the Maryland PSC is a party. Issues similar to those presented in this proceeding are pending in FERC Docket No. EL15-67-000. In EL15-67-000, Linden VFT LLC ("Linden") filed a complaint with the Commission alleging that PJM's reliance on the solution-based DFAX methodology to allocate the costs of certain transmission projects were unjust, unreasonable, and unduly discriminatory and preferential because Linden was assigned cost responsibility that greatly exceeds the benefits it is projected to receive from those transmission projects. While the Linden complaint, at page 50, briefly discussed the Artificial Island Project, the complaint was focused primarily on transmission projects in northern New Jersey.

Specific relief or remedy requested – 18 C.F.R. § 385.206(b)(7).

The relief requested by Complainants is set forth in more detail in the body of this Complaint and specifically in Section V.

Supporting documents – 18 C.F.R. § 385.206(b)(8).

The documents provided in support of this Complaint are identified throughout this Complaint and are attached hereto. The following documents, and their associated exhibits, are appended:

- Appendix 1: Letter From the PJM Board
- Appendix 2: Artificial Island Project Recommendation White Paper

- Appendix 3: Letters to the PJM Board
- Appendix 4: PJM Market Efficiency Study: Artificial Island Benefits
- Appendix 5: April 28, 2015 TEAC Presentation
- Appendix 6: May 8, 2014 TEAC Presentation
- Appendix 7: Affidavit of John M. Marczewski

Prior efforts to resolve this dispute and statement regarding use of alternative dispute resolution – 18 C.F.R. § 385.206(b)(9).

Complainants has voiced their concerns directly to PJM Management and in letters to the PJM Board regarding PJM's proposed allocation of the costs of the Artificial Island Project. The PJM Board, while sympathetic to Complainants' concerns, approved PJM's recommended allocation of the costs of the Artificial Island Project based on a solution-based DFAX methodology because PJM apparently perceived no available alternative under its current Tariff provisions. PJM's public statements, including its filings in FERC Docket No. EL15-67-000, indicate that PJM intends to continue to rely on the solution-based DFAX methodology to allocate the costs of projects such as the Artificial Island Project, without any modifications or exceptions, unless and until the Commission orders a change to the Tariff regarding the application of solution-based DFAX.

The Delaware PSC, along with the Delaware Division of the Public Advocate, also undertook efforts with the PJM Transmission Owners to engage in a discussion about alternatives to the use of solution-based DFAX for the Artificial Island Project. The Delaware PSC discussed the issue and presented options for the PJM Transmission Owners at the August 10, 2015 meeting of the PJM Transmission Owners Agreement-Administrative Committee ("TOA-AC"). By email dated August 14, 2015, a representative of the TOA-AC notified the Delaware PSC that "The TOA-AC, in accordance with the protocols in the CTOA, voted on a motion to act to make changes to the PJM tariff rate design in response to the information received from the Delaware PUC and Public Advocate. The motion failed to receive the 2/3 majority vote required to pass." Subsequent discussions with representatives of the TOA-AC confirmed that further efforts to reach a compromise with the PJM Transmission Owners would not be worthwhile.

Form of notice – 18 C.F.R. § 385.206(B)(10).

A form of notice for this Complaint is attached hereto and submitted in electronic form.

Service on Respondent – 18 C.F.R. § 385.206(c).

Complainants certify that copies of this Complaint are being served by email to the contacts for all Respondents, as those contacts are listed on the Commission's list of Corporate Officials. Any Respondent that prefers to receive a hard copy should contact the undersigned.

VII. CONCLUSION

WHEREFORE, the Delaware Public Service Commission and the Maryland Public Service Commission respectfully request that the Commission:

1. Find that the use of solution-based DFAX, as applied to the Artificial Island Project, will not result in cost allocations that are just, reasonable, and non-discriminatory; and

2. Direct PJM to modify the Tariff and, as necessary, the Operating Agreement to ensure that the costs of the Artificial Island Project are allocated in a manner that is consistent with applicable law.

Respectfully submitted,

/s/ Robert A. Weishaar, Jr.
By: ______________________________

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Counsel to the Delaware Public Service Commission

/s/ Miles H. Mitchell
By: ______________________________

Miles H. Mitchell
Deputy General Counsel
Maryland Public Service Commission
6 St. Paul Street,
Baltimore, MD 21202
Tel: (410) 767-2972

Counsel to the Maryland Public Service Commission

Dated: August 28, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have this day served, via electronic transmission, the foregoing upon representatives of Respondents, as explained in the body of this Complaint.

Dated at Washington, D.C. this 28th day of August, 2015.

/s/ Robert A. Weishaar, Jr.

____

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Delaware Public Service Commission, and Maryland Public Service Commission Complainants, v. PJM Interconnection, L.L.C., and Certain Transmission Owners Designated Under Attachment A to the Consolidated Transmission Owners Agreement, Rate Schedule FERC No. 42 Respondents.	)))))))))))))	Docket No. EL15-___-000

NOTICE OF COMPLAINT

(August ____, 2015)

Take notice that on August 28, 2015, pursuant to Section 206 of the Federal Power Act ("FPA"), 16 U.S.C. § 824(e), and Rule 206 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.206, the Delaware Public Service Commission and the Maryland Public Service Commission ("Complainants") filed a Complaint against PJM Interconnection, L.L.C. ("PJM"), and Certain Transmission Owners asserting that PJM tariff provisions requiring the use of a solution-based DFAX methodology to allocate the costs of the Artificial Island Project are unjust, unreasonable, and unduly discriminatory, in violation of the Federal Power Act, as more fully explained in the Complaint.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondents' answer(s) and all interventions or protests must be filed on or before the comment date. The Respondents' answer(s), motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for electronic review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the website that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on August ______, 2015.

Kimberly D. Bose,
Secretary.

AI Complaint Appendix 1: PJM Board Letter

2750 Monroe Boulevard
Audubon, PA 19403-2497

Terry Boston
President and CEO
610.666.8262
610.666.4281 | FAX

July 29, 2015

ARTIFICIAL ISLAND PROJECT

PJM Members Committee

Dear Members:

After thorough review, the PJM Board of Managers has approved the staff recommendation to accept LS Power's proposal to build a 230 kV line under the Delaware River. The Board also has approved the designation of Public Service Electric & Gas and Pepco Holdings Inc. for the expansion of interconnection facilities. These projects will resolve the operational performance issues around the Artificial Island area and provide important transmission support for the sub region.

The PJM Board greatly appreciates the professionalism and technical expertise demonstrated by the companies offering proposals and by the PJM staff in its review of the proposed projects. The Board also wishes to thank the FERC Administrative Law Judges for their assistance overseeing a key part of this process, as well as other federal and state agencies that helped inform the evaluation for this project.

The competitive process PJM used to consider this project brought forth innovative proposals and a thorough review of performance, cost, constructability and other issues. A "White Paper" fully explaining PJM's analysis and evaluation of the proposals is posted for public review. The PJM Board is pleased to designate a multi-party project among the lowest-cost proposals – one that will fully resolve the stability and voltage issues in this area.

The Board also recognizes the valid concerns raised by Governor Markell, the Delaware Public Service Commission, the Maryland Public Service Commission and others regarding the allocation of costs associated with this project. PJM must follow its Tariff. And with regard to the cost allocation provisions applicable to this project, PJM also must respect legal precedent in the Atlantic City case allocating specific rate filing responsibilities between PJM and its transmission owners. Nonetheless, we recognize that several parties have appropriately questioned the specific allocation in this case. Accordingly, PJM will continue to provide technical analysis and information to affected stakeholders in order to help FERC with its ruling on this particular cost allocation and its cost allocation rules in general.

This pilot case implementing Order 1000 principles and a competitive solicitation process will continue to be examined for a number of "lessons learned." The Board thanks the Planning Committee for its thorough review and we urge the adoption of changes that will improve the planning process.

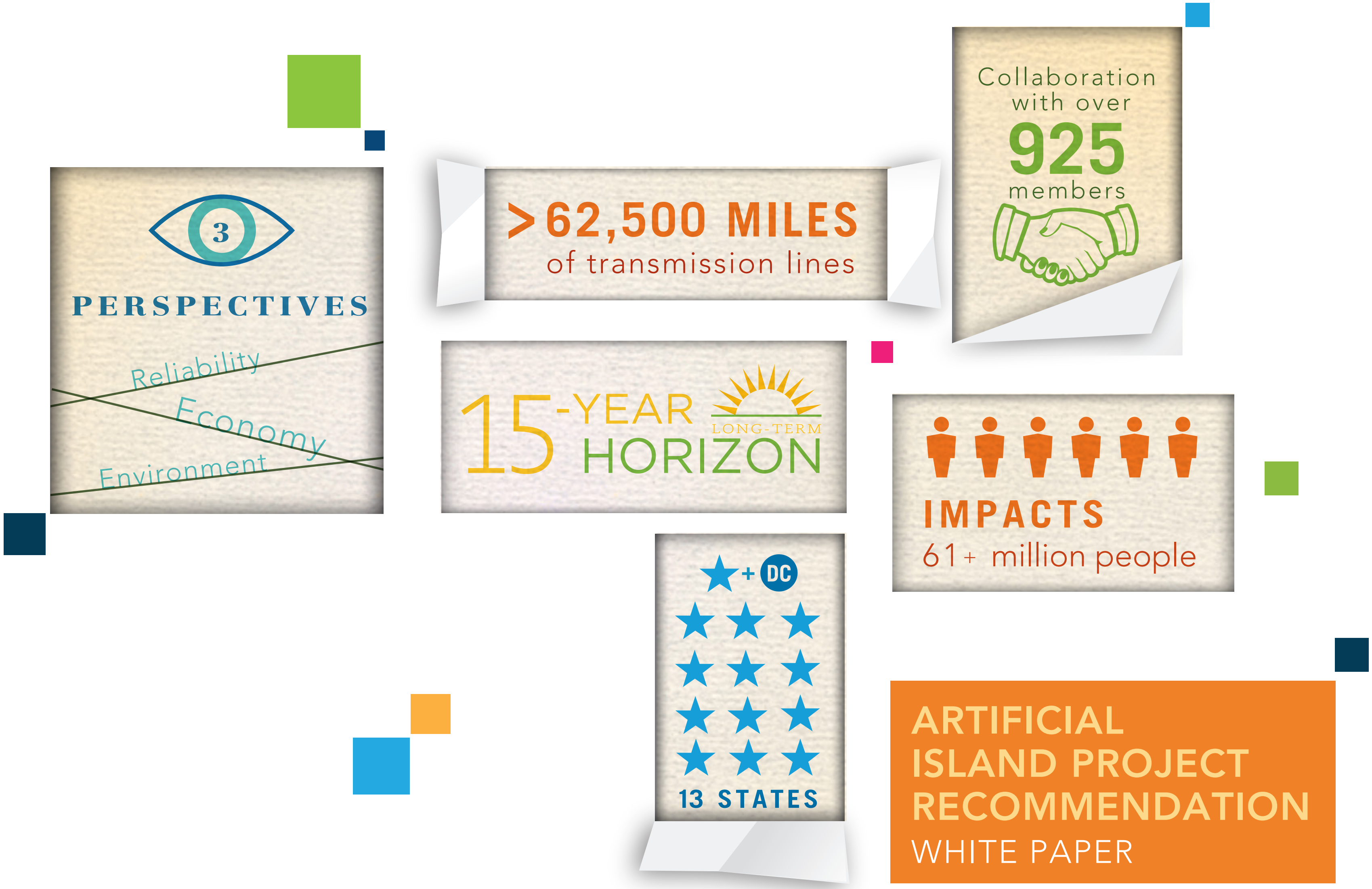
On behalf of the PJM Board, I wish to thank again the companies and regulatory entities that have been engaged in this project selection process.

Sincerely,

Terry Boston

Terry Boston

AI Complaint Appendix 2: White Paper



ARTIFICIAL ISLAND PROJECT RECOMMENDATION

WHITE PAPER

JULY 29, 2015

WORKING TO PERFECT THE FLOW OF ENERGY

Artificial Island White Paper Table of Contents

Section 1 – Executive Summary

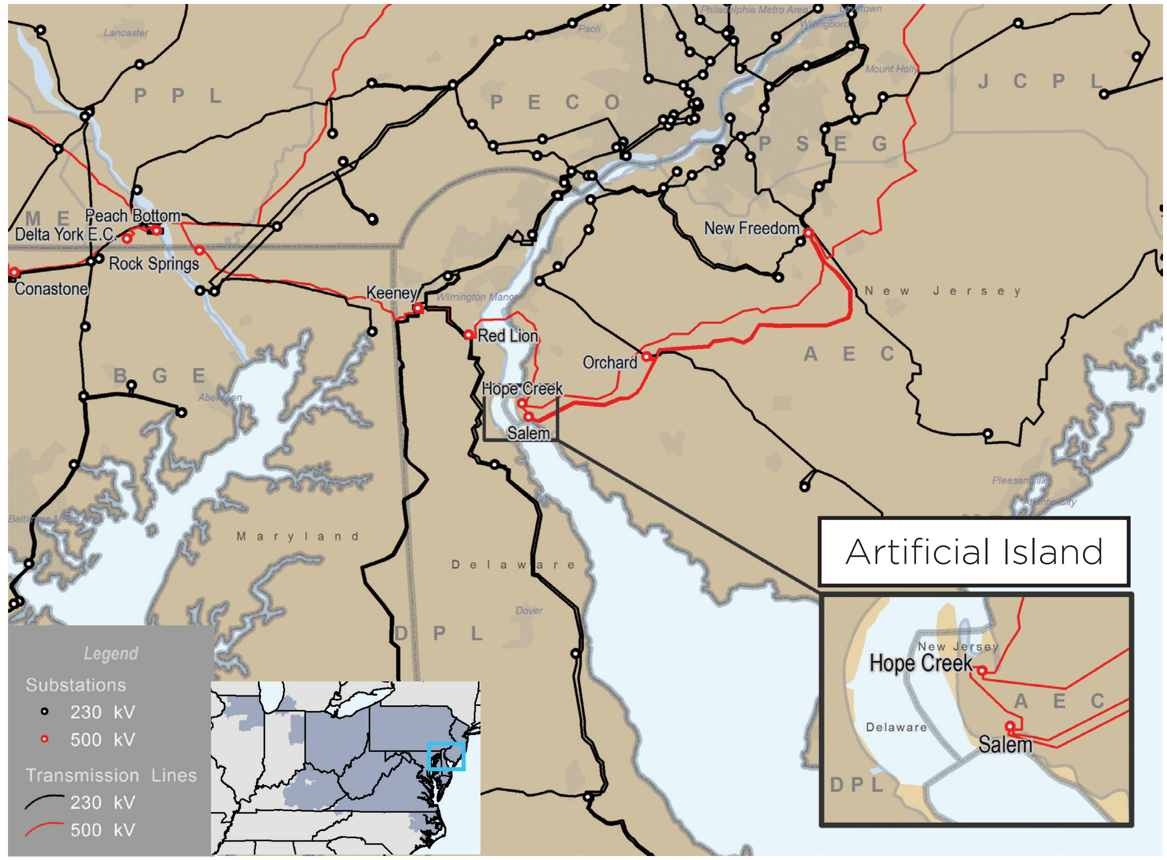
1.0: Executive Summary

1.0.1 — Overview

PJM opened an RTEP process window on April 29, 2013, seeking proposals to improve operational performance on bulk electric system facilities in the southern New Jersey, Artificial Island area, site of PSE&G's Salem 1 and 2 and Hope Creek 1 nuclear generating plants, shown on **Map 1.1**. PJM specified that solution proposals must improve stability margins, reduce Artificial Island MVAR output requirements and address high voltage reliability issues.

Seven different sponsors submitted 26 separate proposals, the various elements of which are shown on **Map 1.2**, with original cost estimates (as submitted) ranging from $100 million to $1.55 billion. A number of proposals included identical or similar elements. Proposals reflected a diverse range of technologies: new overhead and underground/underwater 230 kV lines, new overhead 500 kV lines, HVDC lines, new transformers, new or upgraded substations and related equipment, circuit breakers, system reconfiguration, dynamic reactive devices, dynamic series compensation and DC technology. Proposals spanned a range of project risk exposure levels and lead-time requirements.

Map 1.1: Artificial Island - New Jersey Area



Note:

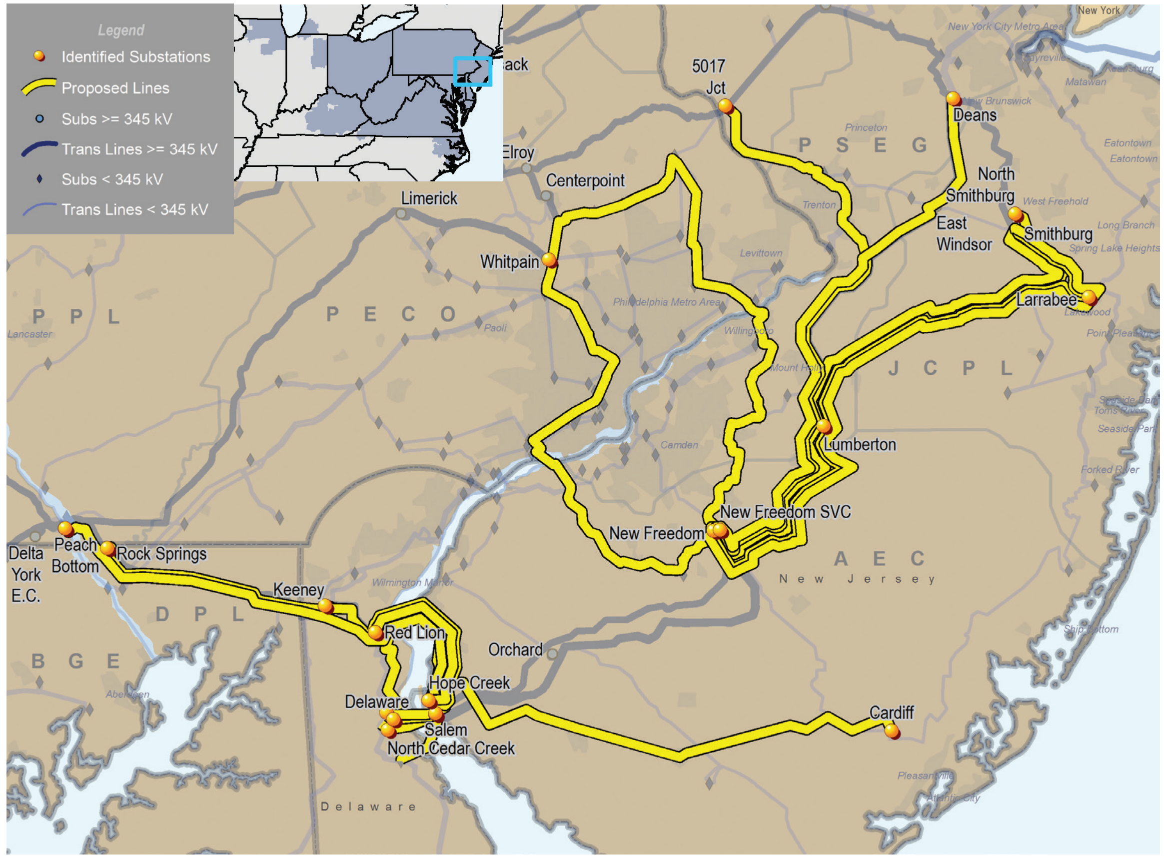
PJM notes that it sought solutions to Artificial Island operational performance issues prior to implementation of its Order 1000 competitive solicitation tariff. As a result, those tariff procedures did not govern this process, a point recently affirmed by the FERC. Nevertheless, PJM utilized those procedures to the extent feasible as a trial run of Order 1000 tariff provisions.

Once the Artificial Island window closed on June 28, 2013, PJM began evaluation of the 26 proposals along three dimensions – system performance, constructability and cost. Initial analytical studies tested proposals in terms of transient stability, voltage, thermal and short-circuit performance against established NERC and regional reliability planning criteria. In parallel, engineering consultant expertise enlisted by PJM evaluated constructability risks to project cost and schedule, such as siting and permitting, rights-of-way and land acquisition, project complexity and operational impact among others. Ultimately, results of system performance, constructability and cost evaluations allowed PJM to identify all or part of five proposals that would be the basis for further consideration and solution development:

- A portion of Proposal PSE&G-7K, which included a 17-mile 500 kV line from Hope Creek to Red Lion, paralleling the existing Red Lion to Hope Creek 500 kV line (designation 5015) and the expansion of the existing Hope Creek and Red Lion substations.

- A portion of Proposal DVP-1C submitted by Dominion Virginia Power, which included an expansion of the existing Hope Creek 500 kV substation and the construction of a 17-mile 500 kV line from Hope Creek to Red Lion, paralleling the existing Red Lion to Hope Creek 500 kV line (designation 5015), as well as a Red Lion substation reconfiguration into a breaker-and-a-half scheme.

Map 1.2: Artificial Island Window Proposals



Note:

A **Static VAR Compensation (SVC)** device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system performance.

A **Thyristor Controlled Series Compensation (TCSC)** device comprises a series capacitor bank shunted by a bidirectional thyristor valve in series with an inductor. This combination of devices is used to lower the apparent line impedance, resulting in increased power transfer capability. A TCSC device makes a long transmission line act like a much shorter one.

- Proposal LS Power-5A, which included expansion of the existing Salem substation to include a new 500/230 kV autotransformer and the construction of a new 230 kV line from that point, under or over the Delaware River to a new substation in Delaware that would tap the existing Red Lion - Carranza and Red Lion - Cedar Creek 230 kV lines.

- Proposal Transource-2B, which included an expansion of the Salem 500 kV substation and the construction of a new substation near Artificial Island with two 500/230 kV autotransformers. The proposal would also include a new 230 kV line from that substation, under the Delaware River, to a new substation in Delaware that would tap the existing Red Lion - Carranza and Red Lion - Cedar Creek 230 kV lines.

- Proposal DVP-1A, submitted by Dominion Virginia Power, which included a new switching station, cutting the Hope Creek - New Freedom 500 kV line (operational designation 5023) and the Salem - New Freedom 500 kV line (operational designation 5024), near New Freedom. The new substation would include 500 kV SVC devices and thyristor controlled series compensation devices in each line.

Additional analytical work, constructability evaluation and stakeholder discussions provided PJM many insights as it developed a solution for recommendation to the PJM Board. These efforts included interviews with the finalists to clarify various items in their proposals with the oversight of a FERC Administrative Law Judge. The judge noted that “PJM treated each bidder equally” and “PJM afforded all four bidders equal opportunity to present their supplemental proposals during the information gathering sessions…”

1.0.2 — Recommendation to the PJM Board

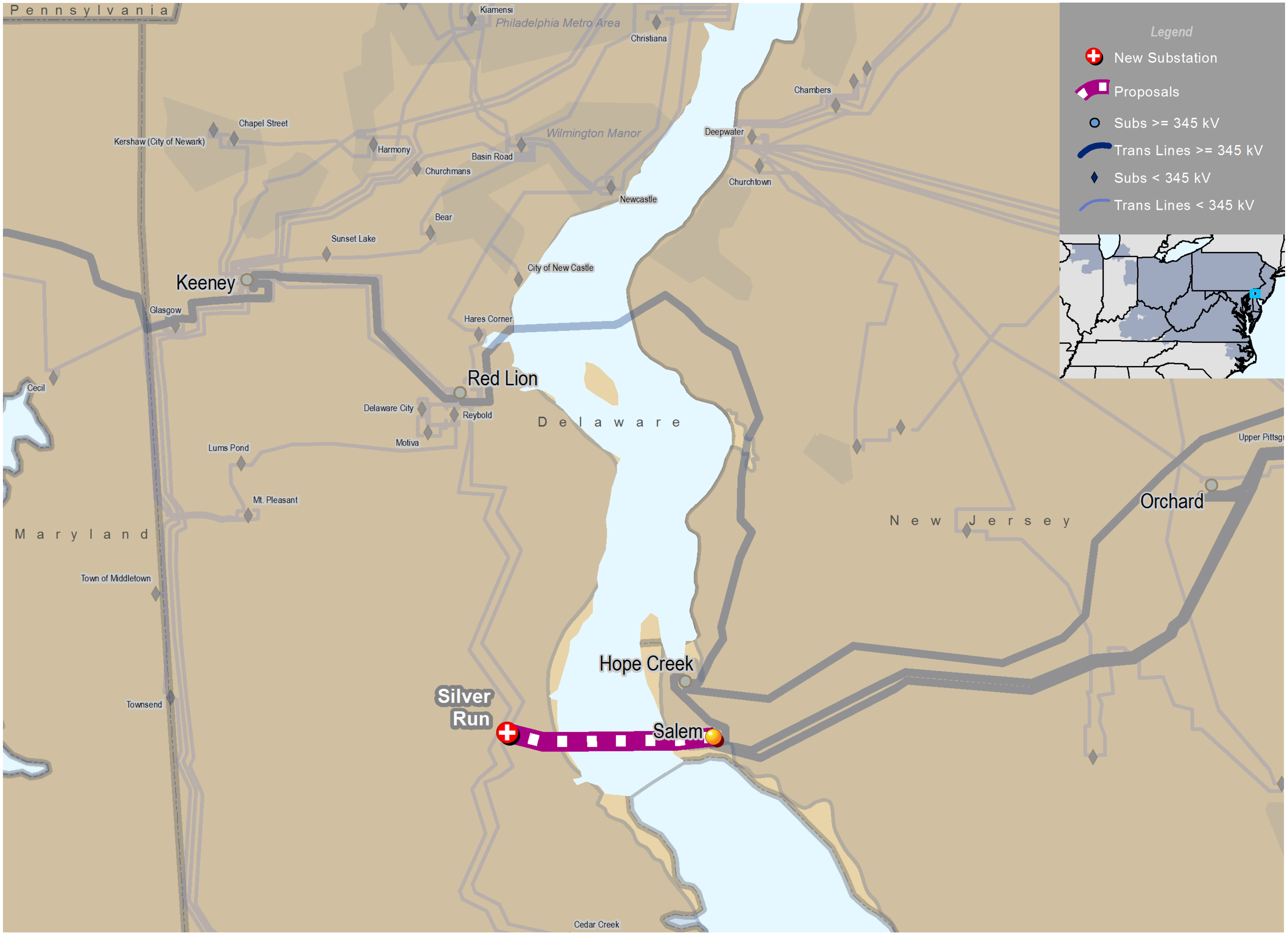
Each project offers certain advantages and risks with regard to performance, cost commitment, and constructability. However, based on the technical analysis and constructability assessments, PJM staff is recommending the following projects to the Board because they represent the best balanced solution that both satisfies the technical performance requirements and provides a constructible solution with reasonable cost commitment.

New 230 kV Transmission Line Delaware River Crossing

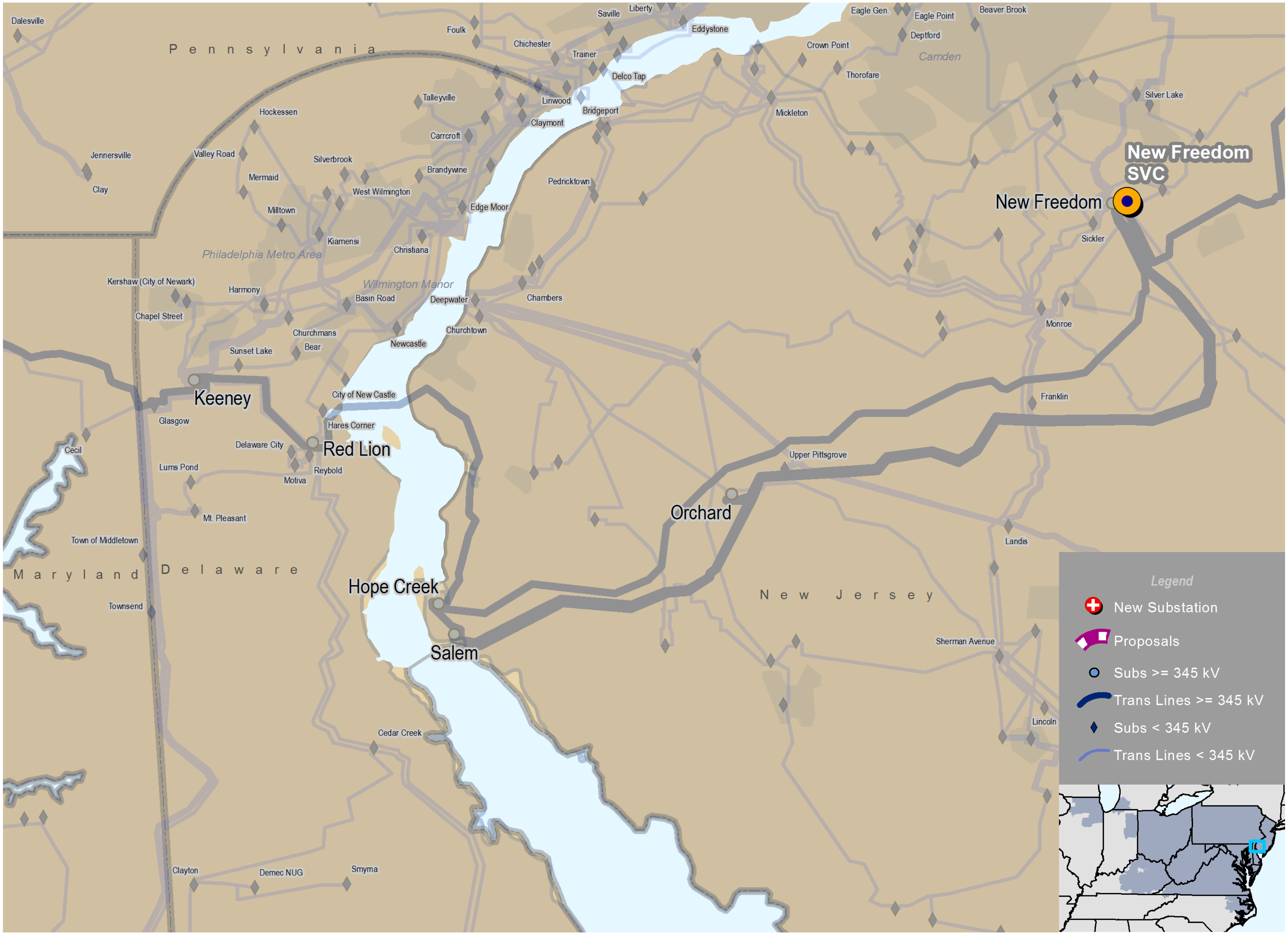
A new 230 kV transmission line to be designated to LS Power should be constructed under the Delaware River from Salem to a new substation in Delaware that would tap the existing Red Lion - Carranza and Red Lion - Cedar Creek 230 kV lines, as shown on **Map 1.3**. Associated substation work at Salem, including existing 500 kV substation expansion and installation of a new 500/230 kV auto-transformer, would be designated to PSE&G. Associated work on the 230 kV right-of-way in Delaware to tap into existing 230 kV lines would be designated to Pepco Holdings, Inc. (PHI).

Among a number of factors, LS Power’s proposed construction technique and cost containment provide notable advantages. From a constructability perspective, utilizing horizontal directional drilling techniques could mitigate permitting risks associated with crossing the Delaware River. Additionally, the LS Power proposal provides greater cost certainty with fewer exclusions to cost commitment compared to the other proposals.

Map 1.3: New 230 kV Transmission Line Delaware River Crossing



Map 1.4: New Freedom 300 MVAR SVC Device



New Freedom 300 MVAR SVC Device

A new 300 MVAR SVC device should be constructed at the New Freedom 500 kV substation, shown on **Map 1.4**, and designated to PSE&G. When compared to the simulations without an SVC device, proposals with SVC devices provided better voltage and machine MVAR response at Artificial Island, correlating to better post-fault system stability operational performance as sought in PJM's request for proposal.

High Speed Optical Grounding Wire Communications

High speed relaying utilizing fiber optic communications installed in optical ground wire should be added to the protection systems of a number of critical 500 kV circuits in the vicinity of Artificial Island, listed below and shown on **Map 1.5**, to provide faster fault clearing times and additional stability margin:

- Hope Creek - Red Lion (operational designation 5015)
- Salem - Orchard (5021)
- East Windsor - Deans (5022)
- Hope Creek - New Freedom (5023)
- Salem - New Freedom (5024)
- Salem - Hope Creek Line (5037)
- New Freedom - East Windsor (5038)
- New Freedom - Orchard (5039)

Doing so will improve the operational performance sought by PJM's request for proposal. Optical ground wire (OPGW) upgrades to these facilities would be designated to PSE&G, PHI and FirstEnergy accordingly.

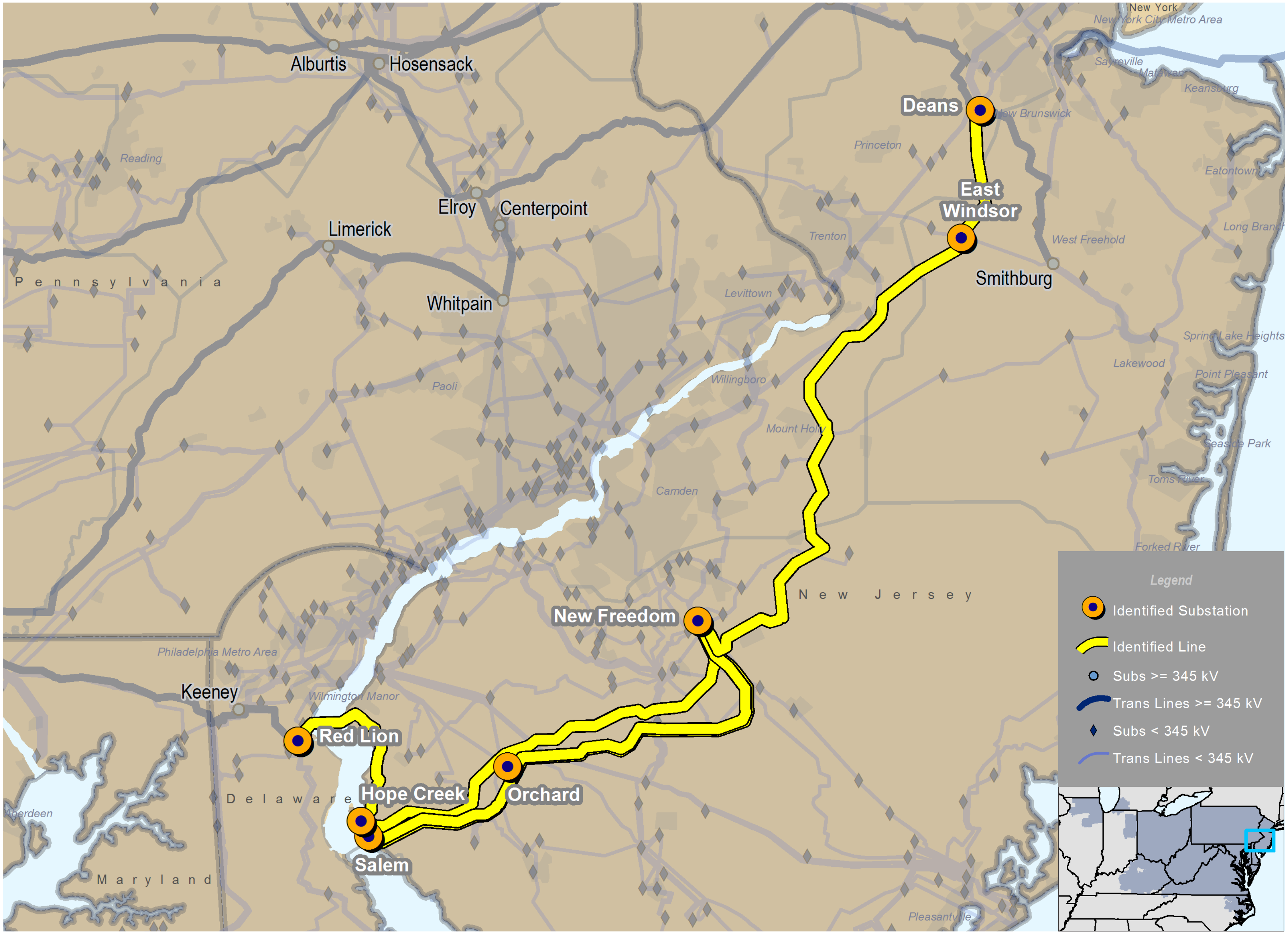
Artificial Island Generator Step-Up Transformer Tap Settings

Tap settings for the generator step-up transformers at the three Artificial Island units – Salem 1, Salem 2 and Hope Creek – to improve the voltage control operational performance. This solution element will be assigned to PSE&G.

1.0.3 — Next Steps

If the PJM Board elects to approve the recommended solution, PJM staff will then notify LS Power that it has been assigned as the Designated Entity for the 230 kV transmission line portion of the solution. PJM will also draft the Designated Entity Agreement and Interconnection Coordination Agreements, which will detail the duties, accountabilities, obligations and responsibilities of each party. The terms of the Designated Entity Agreement will incorporate those presented by LS Power in documents posted publicly on PJM's website and shared with PJM stakeholders. Existing Transmission Owners with responsibility for portions of the recommended solution will also be notified of their respective Designated Entity assignments as well.

Map 1.5: 500 kV Lines for Optical Ground Wire Communications



Section 2 – Artificial Island Window

2.0: Artificial Island Window

2.0.1 — Stating the Issue

PJM conducted its first RTEP proposal window between April 29, 2013, and June 28, 2013 seeking proposals to improve operational performance on bulk electric system facilities in the area of Artificial Island in southern New Jersey, site of the Salem 1 and 2 and Hope Creek 1 nuclear generating plants, shown on **Map 1.1**. Opening the Artificial Island window included publication of a formal problem statement and requirements document comprising PJM's official request for proposals. Specifically, the request sought proposals to eliminate Artificial Island Operating Guide complexity regarding stability limitations and minimum unit MVAR output requirements, as well as to address previously identified high voltage reliability issues. PJM asked that proposals achieve the following objectives:

1. Generate maximum power (3,818 MW total) from all Artificial Island units without a minimum MVAR requirement. Full maximum power must be maintained under both baseline and all N-1 500 kV line outage conditions in the Artificial Island area. Voltages must be maintained within established operating limits and stable for all NERC Category B and C contingencies. N-1-1 contingencies do not need to be applied in addition to the N-1 500 kV outage condition in the Artificial Island area

2. Ensure maximum Artificial Island MW output is not affected by the simultaneous outage of power system stabilizers of Salem Unit 2 and Hope Creek. The Salem Unit 1 power system stabilizer is assumed to be on for all scenarios

3. Reduce operational complexity

4. Improve Artificial Island stability

5. Maintain PJM System Operating Limits (SOLs)

2.0.2 — Artificial Island Area Transient Stability

PJM performs multi-tiered transient stability analyses for system contingencies of reasonable probability as part of its annual RTEP cycle in compliance with NERC TPL standards. These studies examine the grid's ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause a nearby generator's rotor's position to change in relation to the stator's magnetic field, affecting the generator's ability to maintain synchronism with the grid. Power system engineers measure this stability in terms of generator bus voltage and maximum observed angular displacement between a generator's rotor axis and the stator magnetic field – also known as "maximum angle swing." If this swing is in excess of 120 degrees then the generator's ability to remain synchronized may be compromised, requiring additional testing. Generally speaking, lesser angle swing correlates to greater stability margin. Transient stability behavior in actual operations is affected by machine megawatts, system voltage, machine voltage, duration of the disturbance and by system impedance.

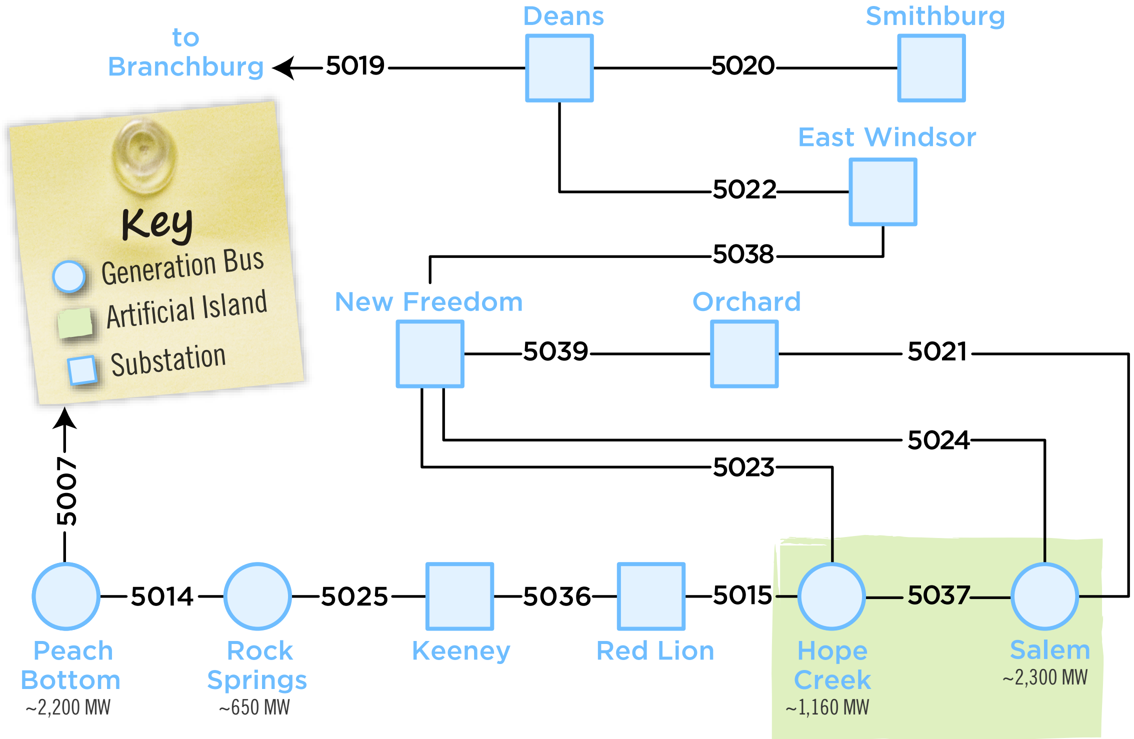
Artificial Island Operating Guide

Historically, Salem and Hope Creek generation output has been constrained by dynamic and transient stability limitations, particularly under transmission line outage scenarios. These constraints have been aggravated by high voltage conditions that have also emerged in actual operations. As a result PSE&G has implemented a special protection system scheme to address these operational issues.

The Artificial Island Operating Guide – included in PJM's manuals – describes the procedures for managing stability limitations. The guide specifies minimum reactive output requirements for each machine at Artificial Island for various operating conditions. The guide has become increasingly complex since 1987 when the special protection system was originally implemented. Many system topology changes – new transmission lines and other facilities as well as generation additions and retirements, for example – have altered operating conditions in southern New Jersey. Over time, the aggregate effects have made the minimum reactive output requirements of the Artificial Island Operating Guide particularly difficult to implement while maintaining system voltages within limits, presenting PJM and PSE&G system operators with limited solutions for remaining within prescribed operating limits to maintain reliability.

As **Figure 2.1** shows, when either the 5015 or 5038 transmission line is out of service, generation output from Artificial Island has limited paths to the remainder of PJM. For example, when 5015 is out of service, the 5038 line becomes the sole 500 kV tie to the rest of the system, and likewise for the 5015 line when 5038 is out of service. Given this topology, the Artificial Island complex is currently subject to both dynamic stability and transient stability restrictions. Power system stabilizers installed on each unit improve dynamic stability. However, if any stabilizers are out of service during three-unit operation, unit reductions and/or increases in MVAR output become necessary.

Figure 2.1: Artificial Island Area 500 kV Single Line Schematic



2.0.3 — The Need for an RTEP Proposal Window

PJM's decision to open an RTEP proposal window has its roots in 2012 RTEP process studies that identified near-term and long-term solutions to improve PJM Artificial Island operational performance. These were reviewed and discussed with TEAC during 2012:

Potential near-term solutions

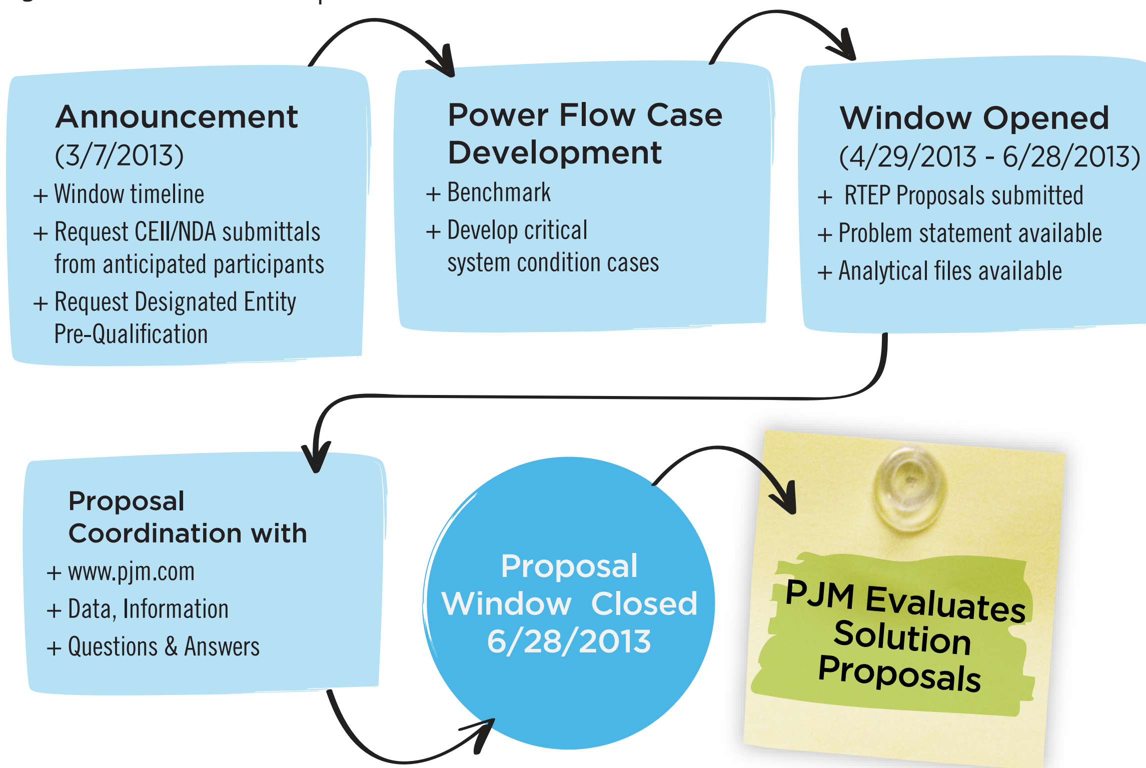
- Consider voltage as an operating guide instead of reactive output
- Fixed or variable reactor at New Freedom, Salem/Hope Creek
- Substation reconfiguration at New Freedom
- Series reactor on line 5037 Hope Creek - Salem
- Braking resistor
- SVC device on 5039 New Freedom - East Windsor 500 kV line

Potential long-term solution

- New 500 kV transmission out of Artificial Island

Ultimately, these TEAC discussions gave rise to the RTEP proposal window announced on March 7, 2013, and opened from April 29, 2013, through June 28, 2013, as shown in **Figure 2.2**.

Figure 2.2: Artificial Island Proposal Window



2.0.4 — Scope of Proposals Submitted

Seven different sponsors submitted 26 separate proposal packages during the RTEP process Artificial Island window. Summarized in **Table 2.1** and shown earlier on **Map 3.2,** cost estimates ranged from approximately $100 million to $1.55 billion and reflected a diverse range of technologies: new transformation, substations and associated equipment, additional circuit breakers, system reconfiguration, dynamic reactive devices, dynamic series compensation and DC technology. Proposals spanned a range of risk exposure and lead-time requirements. PJM conducted both analytical and constructability evaluations to assess the proposals submitted and develop a solution for PJM Board consideration, as discussed next.

Table 2.1: Summary of Artificial Island Window Proposals

Project ID	Proposal Sponsor	Proposal Sponsor Estimated Cost ($M)	Major Components	Supporting Information
P2013_1-1A	Virginia Electric and Power Company	$133	500 MVAR SVC near New Freedom	Two (2) Thyristor Controlled Series Compensation (TCSC) Devices near New Freedom
P2013_1-1B	Virginia Electric and Power Company	$126	New 500 kV from Salem — a new station in Delaware	New 500/230 kV station in Delaware that taps existing Cedar Creek - Red Lion 230 kV and Catanza - Red Lion 230 kV
P2013_1-1C	Virginia Electric and Power Company	$202	New 500 kV from Hope Creek — a new Station in Delaware	Install a new 500 kV line from Hope Creek - Red Lion; New Salem - Hope Creek 500 kV line
P2013_1-2A	Transource	$213 - $269	Salem - Cedar Creek 230 kV	Two (2) 500/230 Transformers near Salem; Loop in Red Lion - Cartanza 230 to Cedar Creek
P2013_1-2B	Transource	$165 - $208	Salem - North Cedar Creek (new) 230 kV	Two (2) 500/230 transformers near Salem and loop in Red Lion - Cartanza 230 and Red Lion - Cedar Creek 230 kV
P2013_1-2C	Transource	$123 - $156	Salem - Red Lion 500 kV	
P2013_1-2D	Transource	$788 - $994	New Freedom - Lumberton - North Smithburg (New) 500 kV line	New Salem - Hope Creek 500 kV line and new 500/230 station east of Lumberton
P2013_1-3A	First Energy	$410.7 (Only FirstEnergy portion)	New Freedom - Smithburg 500 kV line with a loop into Larrabee	Hope Creek - Red Lion 500 kV line
P2013_1-4A	PHI Exelon	$475	Peach Bottom - Keeney - Red Lion - Salem 500 kV	Remove Keeney - Red Lion 230 kV; Reconfigure 230 around Hay Road; Reconductor Harmony - Chapel St 138 kV
P2013_1-5A	LS Power	$116.3 - $148.3	Salem - Silver Run (new) 230 kV; Salem 500/230 kV Transformer	New 230 kV station that taps existing Cedar Creek - Red Lion 230 kV and Catanza - Red Lion 230 kV
P2013_1-5B	LS Power	$170	Salem - Red Lion 500 kV	
P2013_1-6A	Atlantic Wind	$1,012	320 kV HVDC Salem/Hope Creek - Cardiff	SVC at Salem/Hope Creek; New HVDC Stations at Cardiff and Salem
P2013_1-7A	PSE&G	$1,371	Salem-Hope Creek to Peach Bottom 500 kV	Existing ROW
P2013_1-7B	PSE&G	$1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with Loop into Keeney
P2013_1-7C	PSE&G	$1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same at 7A with Loop into Red Lion
P2013_1-7D	PSE&G	$831	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with New ROW
P2013_1-7E	PSE&G	$692	New Freedom - Deans 500 and Salem - Hope Creek 500 kV lines	
P2013_1-7F	PSE&G	$879	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Existing ROW

Table 2.1: Summary of Artificial Island Window Proposals (Continued)

Project ID	Proposal Sponsor	Proposal Sponsor Estimated Cost ($M)	Major Components	Supporting Information
P2013_1-7G	PSE&G	$1,034	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Same as 7F with a Loop into a new Larrabee 500 kV station
P2013_1-7H	PSE&G	$1,177	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Northern Route
P2013_1-7I	PSE&G	$1,353	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Same as 7H with the Southern Route
P2013_1-7J	PSE&G	$915	New Freedom - New Station on Branchburg-Elroy 500 kV line (5017 Junction) and Salem - Hope Creek 500 kV line	Existing ROW
P2013_1-7K	PSE&G	$1,066	New Freedom - Deans and Salem - Hope Creek - Red Lion 500 kV lines with Hope Creek - Red Lion (new)	Same as 7E with Hope Creek - Red Lion
P2013_1-7L	PSE&G	$1,250	New Freedom - Smithburg and Salem - Hope Creek - Red Lion 500 kV lines with Hope Creek - Red Lion (new)	Same as 7F with Hope Creek - Red Lion
P2013_1-7M	PSE&G	$1,548	New Freedom - Whitpain (North) and Salem - Hope Creek - Red Lion 500 kV lines with Hope Creek - Red Lion (new)	Same as 7H with Hope Creek - Red Lion
P2013_1-7N	PSE&G	$1,289	New Freedom — a new Station on the Branchburg-Elroy - 500 kV line (5017 Junction) and Salem - Hope Creek - Red Lion 500 kV lines with Hope Creek - Red Lion (new)	

ROW — right-of-way

Section 3 – Analytical Evaluation

3.0: Analytical Evaluation

3.0.1 — Reviewing the 26 Proposals

PJM's initial review found that only two of the 26 projects as proposed satisfied the operational performance criteria specified in the posted requirements document. Consistent with established RTEP practice, PJM undertook additional engineering review to identify the most effective solution to stated needs, taking into consideration the elements of submitted proposals. Substation configuration changes, device changes such as increasing the size of a Static VAR Compensator (SVC) device, and adding or removing substation components such as circuit breakers and SVC devices improved the performance of several proposals. After subsequent additional analysis, PJM was able to categorize proposals into four groupings based on estimated cost, voltage level, technology and scope, as shown in **Table 3.1**:

- Proposals for southern Delaware River crossings – both overhead and submarine – that terminated at the existing 230 kV system in Delaware
- Proposals for new 500 kV lines from either Hope Creek or Salem substations to the Red Lion 500 kV substation in northern Delaware
- A proposal comprising thyristor controlled series compensation devices near New Freedom
- Proposals with cost estimates more than twice that of the others

Evaluating the Four Proposal Groups

Having identified the four study groups shown in **Table 3.1**, PJM initiated analyses to compare proposals in terms of transient stability, voltage, thermal and short circuit system performance. NERC TPL Standards require that following single contingencies all facilities be within their applicable facility ratings; transient, dynamic and voltage stability are maintained; and, cascading outages or uncontrolled separation do not occur. Analysis of the proposals in each group did not identify any steady-state voltage, thermal or short circuit system reliability criteria violations. Consequently, transient stability – including the need for system oscillations to display positive damping – emerged as a key performance metric as solution development continued.

PJM created over 200 transient stability cases and conducted over 1,000 simulations. Consistent with established practice, stability studies tested system response to three-phase-faults with normal clearing and single-line-to-ground faults with delayed clearing. Where proposal stability studies failed, they did so because simulations encountered transient rotor angle instability for critical contingencies under critical system conditions. Importantly, no stability failure cases were encountered in which damping violations or voltage criteria violations were more critical than transient stability criteria violations.

Delaware River Crossings

PJM conducted additional stability, voltage and thermal performance, short circuit and NERC Category D studies for the Delaware River crossing elements of various proposals. Results of all those tests met required NERC reliability criteria. Additionally, market efficiency production cost simulations revealed economic benefits for river crossings on the order of several million dollars per year, but well below the market efficiency criteria for justification on economics alone.

Initial SVC Device Analysis

PJM staff studies showed the effectiveness of a number of the proposals could be improved with the addition of a dynamic reactive device. PJM evaluated SVC device effectiveness at Artificial Island, Orchard and New Freedom 500 kV substations shown earlier on **Map 1.4** by observing Artificial Island MVAR output and maximum angle swing. Study results revealed that the closer the SVC device location was to Artificial Island, the better the voltage response and the smaller the machine angle swing. When compared to the simulations without an SVC device, proposals with SVC devices provided better voltage and machine MVAR response at Artificial Island, correlating to better post-fault system stability.

Table 3.1: Artificial Island Project Proposals Grouped by Scope and Cost

Analytical Study Group	Group 1: Artificial Island to Delmarva 230 kV System between Cedar Creek and Red Lion				Group 2: Artificial Island to Red Lion 500 kV					Group 3: TCSC Near New Freedom 500 kV	Group 4: Higher Cost Solutions
Project ID	P2013_1-1B	P2013_1-2A	P2013_1-2B	P2013_1-5A	P2013_1-1C	P2013_1-2C	P2013_1-4A	P2013_1-5B	Various	P2013_1-1A	P2013_1-2D, P2013_1-3A, P2013_1-6A, P2013_1-7A, P2013_1-7B, P2013_1-7C, P2013_1-7D, P2013_1-7E, P2013_1-7F, P2013_1-7G, P2013_1-7H, P2013_1-7I, P2013_1-7J, P2013_1-7K, P2013_1-7L, P2013_1-7M, P2013_1-7N
Project Sponsor	Virginia Electric and Power Company	Transource	Transource	LS Power	Virginia Electric and Power Company	Transource	PHI Exelon	LS Power	PSE&G	Virginia Electric and Power Company	
Approximate Cost Range	$115 M - $275 M				$125 - $300 M					$133	$692 - $1,548 M

TCSC — Thyristor Controlled Series Device

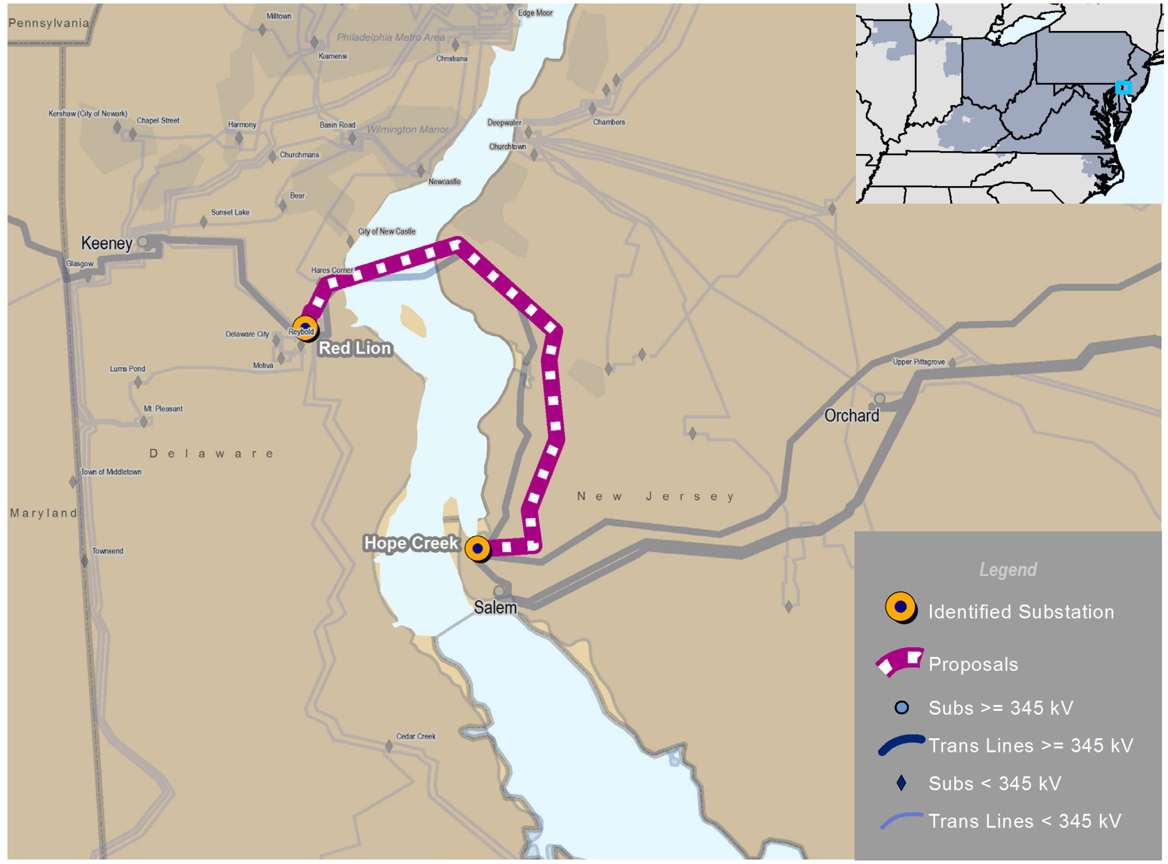
3.0.2 — Further Analytical Evaluation of the Five Finalists

As analytical, constructability and cost evaluations proceeded – as discussed in **Sections 4** and **5** – PJM was able to narrow the list of viable solution options from 26 to five:

- Proposal PSE&G-7K, shown on **Map 3.1,** included a 17-mile 500 kV line from Hope Creek to Red Lion, paralleling the existing Red Lion to Hope Creek 500 kV line (designation 5015), and the expansion of the existing Hope Creek and Red Lion substations.

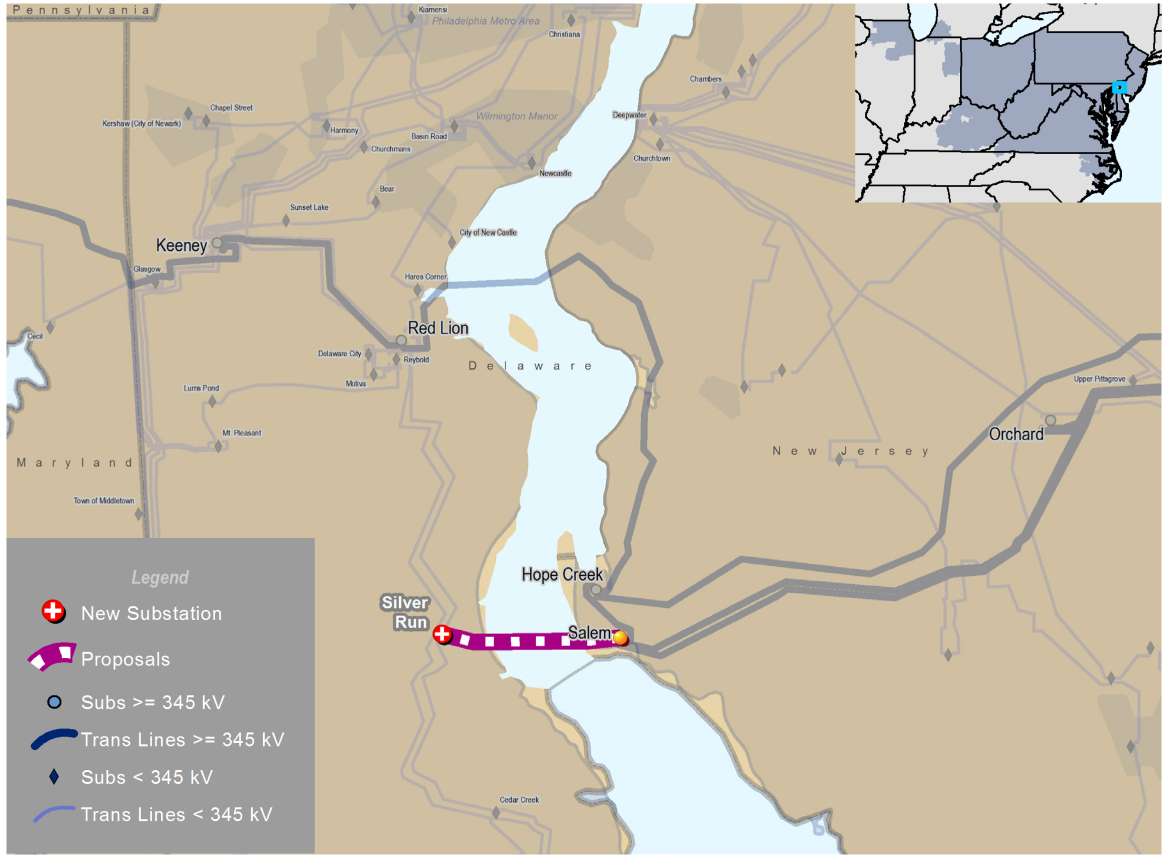
- Proposal DVP-1C, also shown on **Map 3.1**, submitted by Dominion Virginia Power, included an expansion of the existing Hope Creek 500 kV substation and the construction of a 17-mile 500 kV line from Hope Creek to Red Lion, paralleling the existing Red Lion to Hope Creek 500 kV line (designation 5015) and also included Red Lion substation reconfiguration into a breaker-and-a-half scheme.

Map 3.1: Proposal PSE&G-7K and Proposal DVP-1C



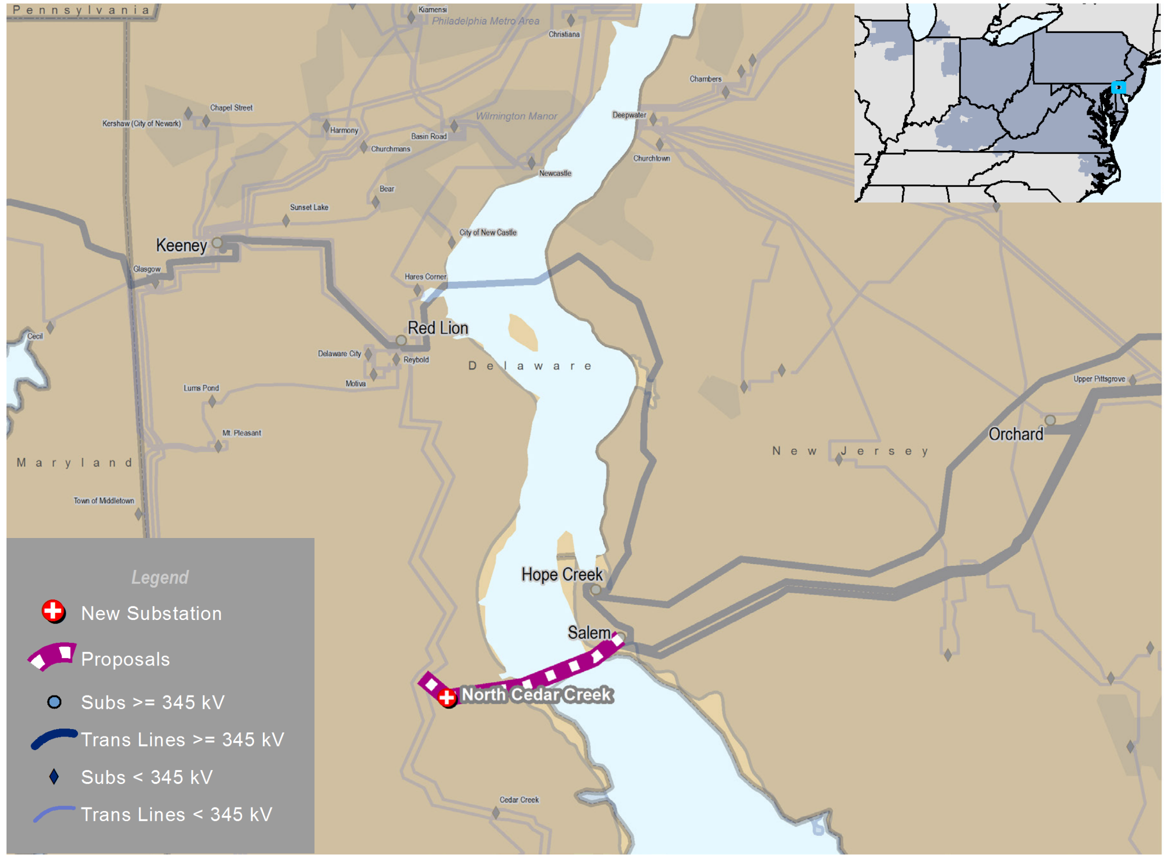
- Proposal LS Power-5A, shown on **Map 3.2,** included existing Salem substation expansion for a new 500/230 kV autotransformer and construction of a new 230 kV line from that point, under or over the Delaware River, to a new substation on the Delmarva Peninsula that would tap the existing Red Lion - Carranza and Red Lion-Cedar Creek 230 kV lines.

Map 3.2: Proposal LS Power-5A



- Proposal Transource-2B, shown on **Map 3.3,** included an expansion of the Salem 500 kV substation and the construction of a new substation near Artificial Island with two 500/230 kV autotransformers. The proposal would also include a new 230 kV line from that substation, under the Delaware River, to a new substation on the Delmarva Peninsula that would tap the existing Red Lion - Carranza and Red Lion-Cedar Creek 230 kV lines

Map 3.3: Proposal Transource-2B



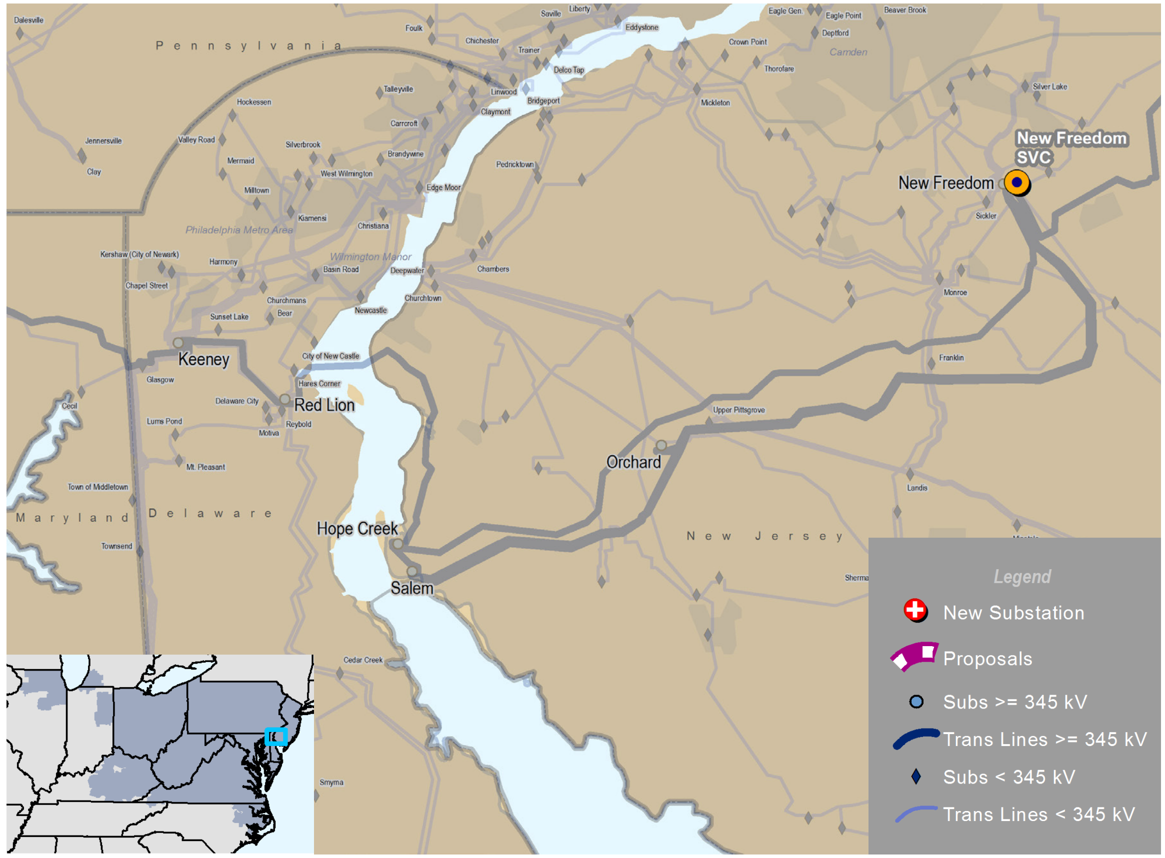
- Proposal DVP-1A, shown on **Map 3.4,** submitted by Dominion Virginia Power, included a new switching station, cutting the Hope Creek-New Freedom 500 kV line (operational designation 5023) and the Salem-New Freedom 500 kV line (5024), near New Freedom. The new substation would include 500 kV SVC devices and a thyristor controlled series compensation device.

Sensitivity Studies

Focusing on the proposals of the five finalists, PJM proceeded with sensitivity studies to evaluate system performance in light of several additional solution elements:

- Artificial Island generator step-up transformer (GSU) tap setting adjustments to improve voltage control
- SVC device installation at New Freedom in combination with the four transmission line proposals to help provide reactive power to control dynamic voltage swings
- Optical ground wire communications and new protection systems on a number of critical 500 kV circuits in the vicinity of Artificial Island:
  - Hope Creek - Red Lion (operational designation 5015)
  - Salem - Orchard (5021)
  - East Windsor - Deans (5022)
  - Hope Creek - New Freedom (5023)
  - Salem - New Freedom (5024)

Map 3.4: Proposal DVP-1A



  - Salem - Hope Creek Line (5037)
  - New Freedom - East Windsor (5038)
  - New Freedom - Orchard (5039)

This would provide faster fault clearing times, thereby improving stability margin and the operational performance sought by PJM's request for proposal.

3.0.3 — Sub-Synchronous Resonance (SSR)

Sub-synchronous resonance (SSR) is the build-up of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, even catastrophic loss. The term "sub-synchronous" refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles-per-second). Power plants close to series compensation devices may be prone to SSR. Specific technical analysis – such as that performed by consultants for PJM – can assess the potential for SSR to arise.

Specifically, the Dominion 1A proposal includes a new substation with a 750/-375 MVAR static VAR compensator (SVC) device plus two thyristor controlled series compensation devices, one each on the Salem–New Freedom 500 kV line and Hope Creek–New Freedom 500 kV line. PJM engaged consultant expertise to conduct a screening study to assess the potential for the device to create SSR conditions on Salem and Hope Creek turbine shafts. Using available mass moment-of-inertia and torsional model data for the machines at Artificial Island, studies evaluated the SSR impact by simulating a disturbance on the base operating scenario and monitoring the coupling torque in the shaft model. Screening study results, while far from conclusive, identified potential "negative damping" at Artificial Island for several resonant frequencies. In other words, the shaft would have the potential to experience growing, damaging oscillations at a frequency below 60 Hz.

PJM enlisted a separate, independent consultant to review the screening study results. The following recommendations and observations were made:

Detailed Spring-Mass Models

Detailed spring-mass models of the turbine-generator shaft system should be considered when assessing the actual potential risk of SSR, particularly torsional interactions.

Post-Contingency Thyristor Controlled Series Compensation Level

The 90 percent *post-contingency* thyristor controlled series compensation level proposed by Dominion should be examined further. PJM's consultant identified 70-80 percent as the upper limit used for series capacitive compensation in industry power system applications today. A 90 percent level leaves little operating margin for avoiding SSR. From an engineering perspective, post-contingency compensation at 100 percent would effectively create a reactance roughly equal to zero, causing difficulty controlling transient voltages and currents following a system disturbance.

Real-Time Digital Power System Simulation

PJM's consultant also recommended additional study using real-time digital power system (RTDS) simulation to lend additional credibility to screening studies. More detailed modeling of the turbine-generator shaft system, the two thyristor controlled series compensation devices and the SVC device would provide simulation results much closer to actual operating conditions. The effectiveness and robustness of the thyristor controlled series compensation control systems and interactions with neighboring controlled equipment could also be validated.

Conducting a real-time digital power system study itself is complex. PJM consulted Dominion, who has this simulation capability to identify what would be required to do so. Once all required machine data were obtained, an estimated 26 weeks would be required for study completion. However, as modeling parameter data can likely only be obtained in coordination with a generating unit outage, significant risk of study delay also exists. Additionally, the 26 weeks does not include review time between various study stages.

3.0.4 — Transient Stability Margin

In engineering terms, suddenly changing the system impedance when lines fail, or when load is added or removed, causes a generator rotor to decelerate, accelerate or swing with respect to the stator magnetic field. Under such conditions, a generator can become unstable, causing relays to trip the unit within several cycles following the fault to avoid unit damage. Computer simulations study transient stability for several seconds, where one second equals 60 cycles or Hertz (Hz). If the system is found to be stable during the first swing, subsequent swings are likely to be less severe – "dampened" – allowing the system to return to a stable state thereafter. To that end, PJM conducted a series of studies to ensure Artificial Island unit transient stability following a 500 kV line tripping during the maintenance outage of another critical 500 kV line in the same area.

Table 3.2: Transient Stability Study Results – Margin Analysis

Project Name	OPGW and GSU Tap Optimization	TCSC: Normal / Transient	SVC Device Size	Max Angle Swing (Degrees)	Fault Clearing Time (Cycles)	CCT (1) (Cycles)	Margin to CCT (Cycles)	M14B Margin (Cycles)	Margin Results (Cycles)
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10
LS Power P2013_1-5A 230 kV	Yes	N/A	0	114	9.06(5)	9.31	0.25	0.50	**-0.25**
			300 MVAR	91	9.06	10.31	1.25	0.50	0.75
	No		650 MVAR	112	10.40	10.65	0.25	0.50	**-0.25**
Transource P2013_1-2B 230 kV	Yes	N/A	0	107	9.06	9.56	0.50	0.50	**0.00**
			300 MVAR	88	9.06	10.56	1.50	0.50	1.00
	No		650 MVAR	109	10.14	10.64	0.50	0.50	**0.00**
PSE&G P2013_1-7K 500 kV	Yes	N/A	0	100	9.06	9.81	0.75	0.50	0.25
			300 MVAR	83	9.06	10.81	1.75	0.50	1.25
	No		650 MVAR	107	4.02	4.27	0.25	0.25	**0.00**
DVP P2013_1-1C 500 kV	Yes	N/A	0	100	9.06	10.06	0.75	0.50	0.25
			300 MVAR	83	9.06	10.81	1.75	0.50	1.25
	No		650 MVAR	107	4.02	4.27	0.25	0.25	**0.00**
DVP P2013_1-1A TCSC only	Yes	40,45/90%	0	**Unstable**	**2.90**	**< 2.90**	-	-	-
DVP P2013_1-1A TCSC + SVC		40,45/90%	500 MVAR	93	2.90	3.15	0.25	0.25	**0.00**
		0/50%	750 MVAR	99	2.90	2.90	0.00	0.25	**-0.25**
		0/70%	750 MVAR	81	2.90	3.40	0.50	0.25	0.25

300 MVAR SVC Results — Criteria Violation

TCSC – Thyristor Controlled Series Compensation
OPGW – Optical Ground Wire
GSU – Generator Step-Up Transformer
SVC – Static VAR Compensation
CCT – Critical Clearing Time

Study Results

As **Table 3.2** shows, PJM conducted transient stability tests for each of the finalist proposals (Column 1) under varying SVC device sizes (Column 4) both with and without optical ground wire and generator step-up transformer tap optimization (Column 2). Across 15 of the 16 cases studied, maximum machine angle ranged from 81 to 114 degrees (Column 5) but did not become unstable. A sixteenth project - DVP P2013_1-1A – exhibited instability. PJM conducted that particular run in order to model Dominion's thyristor controlled series compensation project without its associated proposed SVC device to confirm if it would be needed for the proposal to be effective. As studied, the thyristor controlled series compensation case without a SVC device became unstable within three cycles.

Transient stability studies for the same 15 runs also confirmed that sufficient fault clearing time margin existed for each alternative before transient instability would otherwise occur. As **Table 3.2** shows, the 15 cases had "as-designed" relay fault clearing times (Column 6) that were less than the maximum (critical) fault clearing time (Column 7), the point after which that case became unstable. Subtracting the "as-designed" clearing time value from the maximum fault clearing time yielded transient stability margins (Column 8) from 0.00 to 1.75 cycles.

Regional Reliability Requirements

PJM's regional reliability requirements also require that studies evaluate remaining transient stability margin (Column 10) after a one-fourth and one-half permissible cycle of fault clearing time (Column 9) is deducted, to account primarily for uncertainty in actual clearing times. As **Table 3.2** shows, PJM added 0.25 cycle margin for normally cleared faults and 0.5 cycle margin for faults with delayed clearing time.

The results (Column 10) revealed zero or negative margin for eight of the 15 cases (indicated in red in Column 10). Notably, the greatest transient margin – between 0.75 and 1.25 – was observed for proposals which included a New Freedom SVC device with 300 MVAR capability (Column 4).

3.0.5 — Technical Observations

Based on the technical evaluation, PJM noted the following key points:

- A 300 MVAR SVC device at New Freedom provides key operational performance benefits needed under fault conditions: transient stability margin to meet PJM's regional planning criteria and reactive power to control dynamic voltage swings.

- Artificial Island generator step-up transformer (GSU) tap setting adjustments improve voltage control.

- Optical ground wire (OPGW) communications added to the protection systems of eight identified 500 kV circuits in the vicinity of Artificial Island provides faster fault clearing times.

- Thyristor controlled series compensation presents downside challenges with respect to sub-synchronous resonance and transient stability: (1) the necessary real-time data simulator SSR study would require six months after data acquisition that is tied to Salem and Hope Creek unit outages; (2) the 90 percent post-contingency thyristor controlled series compensation level is well above 70-80 percent industry norms; and (3) transient stability performance at lower compensation levels is not as robust as that provided by transmission line solutions.

Reliability studies comprised just one component of PJM's overall evaluation of Artificial Island proposals. Constructability evaluation provided PJM with additional key information in developing its recommendation to the PJM Board, as discussed next.

Section 4 – Constructability Evaluation

4.0: Constructability Evaluation

4.0.1 — Assessing Project Risks

In parallel with analytical evaluation, PJM enlisted engineering consultant expertise to evaluate project proposal constructability – cost, scheduling, siting, permitting, rights-of-way and land acquisition, project complexity, coordination and other risk areas. Any one or more factors could impact project completion or increase project costs. PJM consultants drew attention to a number of such factors. This section first discusses constructability risk factors across many proposals regardless of whether they are northern or southern route based. Then, **Section 4.0.2** and **Section 4.0.3** go on to highlight key factors pertinent to the northern route and southern route proposals.

Regulatory and Permitting Agencies

All projects evaluated included the need to acquire land and rights-of-way. Much of PJM's constructability evaluation focused on the potential risks associated with Delaware River crossings – either overhead or submarine – that were elements of 18 proposals. Nearly 50 different federal, state and local permits and agencies could be involved. PJM had discussions with a number of these agencies to understand the scope of permitting and other issues:

- New Jersey Department of Environmental Protection
- United States Army Corps of Engineers
- National Oceanic and Atmospheric Administration
- United States Fish and Wildlife Service
- Delaware Department of Natural Resources and Environmental Control

Meetings with these agencies assisted PJM with identifying cost and scheduling risks associated with project complexity, rights-of-way, land acquisition, siting, permitting and public opposition. Several important considerations emerged:

- The permitting issues identified by consultants are consistent with the kind of constructability reviews and stakeholder comments associated with other prior transmission projects.
- River crossings must address the regulatory requirements of the U.S. Army Corps of Engineers, Delaware River Basin Commission, U.S. Coast Guard and National Marine Fisheries Service.
- State CPCN filings must address potential wetland, view-shed, archeological, transportation infrastructure, endangered species, historic, parks, and other environmental and cultural resource impacts.

Note:

The following index of regulatory names and acronyms is provided for ease of reference throughout this section.

- Certificate of Public Convenience and Necessity – CPCN
- Code of Federal Regulations – CFR
- Delaware Department of Natural Resources and Environmental Control – DNREC
- Delaware Public Service Commission – DEPSC
- Delaware River Basin Commission – DRBC
- Environmental Impact Statement – EIS
- National Environmental Policy Act – NEPA
- National Oceanic and Atmospheric Administration – NOAA
- New Jersey Board of Public Utilities – NJBPU
- New Jersey Department of Environmental Protection – NJDEP
- Nuclear Regulatory Commission – NRC
- United States Army Corps of Engineers – USACE
- United States Fish and Wildlife Service – USFWS

The National Environmental Policy Act (NEPA) defines the federal environmental permitting process and will have a major impact on path feasibility: the environmental effects of transmission projects requiring navigable water crossings, for example. PJM's consultants indicated a possibility that a full Environmental Impact Statement (EIS) would be required, which can extend a project schedule by one to two years.

The Delaware River is also an important flyway for migratory birds. Any options that involves an overhead line and associated tower structures could cause potential impact. The need for bird diversion devices placed on the towers and conductors would mostly likely be identified through the consultation and permitting process with federal agencies like the USACE and the U.S. Fish and Wildlife Service (Migratory Bird Treaty Act). Project cost and schedule could be affected.

Wetlands/Endangered Species

All proposed routes would cross wetlands and potentially impact threatened or endangered plants and animals, requiring consultation with state and federal agencies, including the USACE. In some instances, like a crossing of the Delaware River itself, before-and-after environmental studies may be required. These could take up to two years to complete before approval could be granted.

Public Opposition

PJM's consultants emphasized that public opposition should be expected. Many of the proposals include a Delaware River crossing either by overhead or submarine cable. Temporary impacts from submarine cable construction may be viewed as less harmful than the potential permanent impacts to view-shed, migratory bird flyways and other environmental impacts from an overhead river crossing. In general, public opposition has occurred more often with overhead than submarine options.

Impacts to the scenic river landscape and aquatic habitats together with safety concerns of commercial shipping traffic and recreational watercraft can generate the biggest objections to an overhead crossing. Consultant review of other recent river crossings also suggested that when siting and permitting overhead electric transmission lines, visual impacts from tall transmission tower structures routinely experience high levels of public opposition.

Rights-of-Way

Proposed transmission lines comprising new facilities require new rights-of-way. In Delaware, utilities do not have eminent domain authority subject to state law. Rather, they must negotiate with private property owners for easements for new facilities. This lack of eminent domain authority must be addressed in budget and timeline assumptions.

Existing Facility Expansion

The extent to which proposals require modifications to the Artificial Island substations must be considered. A solution that minimizes modifications at Salem in particular would be preferable. Space for expansion is limited and installing new protection and control equipment in the secure area of Salem generating station adds to project complexity.

- Any 500 kV line bay additions to the Salem substation would require careful design given the proximity to the Salem 1 generator step-up transformer leads. Installing equipment in this section of the substation would impede access to station auxiliary transformers.

- All Salem substation controls are located within the protected area of the generating station. Currently, only limited spare conduit from the substation back into the plant is available that could be used for any of the control cable associated with the new substation facilities.

- New Salem to Red Lion 500 kV transmission lines would encounter the need to relocate and/or cross existing lines. Line crossings add design, construction and operational complexity.

By comparison, expansion space and design complexity are less of an issue at the Hope Creek substation:

- Sufficient space exists to accommodate a new 500 kV line bay for a transmission line to Red Lion.
- Using existing space would not significantly impede access to station equipment compared to the alternatives out of Salem. Hope Creek substation equipment controls are located in a separate control building in the substation yard, eliminating the need to run new control cable into protected areas.
- A new 500 kV line from the Hope Creek substation to Red Lion would not introduce any new 500 kV line crossing.

Coordination with incumbent substation owners would be necessary before a final design could be developed. Additionally, construction could require numerous sequential outages.

Outages Required for System Expansion

Transmission Owner and Generation Owner coordination would be necessary to address the need for construction sequencing, existing facility relocation, expansion, modification and reconfiguration complexities. All projects will require outages to connect to the existing grid. In particular, outages of the existing Red Lion-Hope Creek 500 kV line (operational designation 5015) have historically proven to be difficult to schedule for any extended duration. Outage delays could jeopardize project completion within the planned schedule and budget. By way of example, one project as proposed would require three outages on the 5015 line totaling approximately 40 days. Artificial Island is geographically and electrically located close to several other Transmission Owner zones – Atlantic Electric, Jersey Central Power and Light, Delmarva Power and Light. Outages of existing facilities in the area must be closely coordinated among PJM and them.

Nuclear Plant Safety

PSE&G Nuclear raised concerns regarding the potential for SSR events if thyristor controlled series compensation technology were to be implemented. In evaluating the impact of any project to the Artificial Island facility, the nuclear licensee (PSE&G Nuclear) performs a 10CFR50.59 Safety Evaluation. If the evaluation identifies nuclear safety impacts that require a technical specification change, then NRC approval would be required. The NRC did not raise concerns about the use of compensation devices in the vicinity of Artificial Island.

Ongoing Maintenance

All projects would impose ongoing operational impacts to existing Artificial Island facilities to some degree. However, proposals that include Salem substation modification are likely to have greater impact. The 230 kV based projects are likely to impose on-going maintenance needs given their associated 500/230 kV transformers and appurtenant facilities. Projects that would utilize portions of the Salem substation would likely have additional maintenance needs caused by salt contamination given its proximity to Delaware Bay estuaries.

4.0.2 — Northern Route Risk Factors

PJM's independent consultants evaluated the constructability of a 500 kV transmission line from Artificial Island in Salem County, N.J., to the Red Lion 500 kV substation in New Castle County, Del. Based on their high-level review and analysis of the proposed projects, the proposed transmission line would most likely be feasible but the existence of several potential construction risks could affect the estimated costs and schedules proposed by the submitting entities.

Construction Challenges

The landscape crossed by the line introduces a number of construction challenges with respect to both river crossing and on-land elements. The installation of structures and foundations in the Delaware River and coastal wetlands would introduce challenging access to structure locations, requiring extensive use of swamp mats and helicopter installation. Additionally, the river crossing element could potentially raise navigational concerns, depending on the location of the towers within the river.

Permitting and Agency Risk Factors

Permitting of state lands and wetlands, cultural resources investigations and demonstration of public need could raise regulatory and right-of-way acquisition challenges. Consultants highlighted a number of permitting risks. In addition to the need to adopt special construction techniques for specific wetland types and field conditions, the type of wetlands has significant implications from a permitting and compensatory mitigation perspective. Forested wetlands in general tend to be considered a more sensitive, higher-quality resource than other wetlands types given their ecological diversity, comparative rarity and long recovery time once disturbed. Although no critical habitats have yet been identified within the project study area, if a protected species or suitable habitat is identified during field surveys, specific mitigation measures may be required – timing restrictions and buffer zones, for example. However, in the absence of project-specific agency consultation, survey and mitigation requirements are uncertain.

The proposed northern route project corridor would cross three federally managed properties located within New Jersey: USFWS Supawna Meadows National Wildlife Refuge, USFWS Artificial Island and United States Army Corps of Engineers (USACE) Killcohook Coordination Area (formerly Killcohook Migratory Bird Refuge). The proposed route would also cross state public lands managed by New Jersey and Delaware, including wetland restoration sites, conservation areas and wildlife management areas. As with all properties on the proposed project route, the developer would need to seek access permission for pre-construction engineering and environmental surveys, as well as easement rights before the project goes to construction. The project requires coastal zone management approval from New Jersey Department of Environmental Protection (NJDEP) and Delaware Department of Natural Resources and Environmental Control (DNREC), which may involve a lengthy review process depending on construction techniques and proposed pathways needed to access the right-of-way. The project itself could potentially impact 32 acres of forested wetlands.

The Delaware River Basin Commission (DRBC) has regulatory mechanisms in place that drive overall state-level environmental evaluation. The New Jersey Board of Public Utilities Commission (NJBPU) and Delaware Public Service Commission (PSC) would coordinate with the NJDEP and DNREC through the process that leads to issuance of Certificate of Public Convenience and Necessity (CPCN), in the case of New Jersey. Issuance would likely occur concurrently with USACE, USFWS and state agency approvals. The state commissions would be hesitant to approve the project without assurance that it is being coordinated with NJDEP and DNREC.

Supawna National Wildlife Refuge

Crossing the Supawna National Wildlife Refuge could be challenging and difficult with the availability of other viable alternatives. Permitting must address the combination of technical and regulatory complexities associated with the combined approximately six-mile line section that crosses the federally protected wildlife refuge. A right-of-way permit will need to be obtained from USFWS to cross Supawna National Wildlife Refuge. The process for obtaining easements on federally managed lands is typically lengthy and complex. If the project becomes controversial, the permitting process may extend well beyond the anticipated project schedule.

Operational Robustness

The northern 500 kV options were considered to be more operationally robust than the 230 kV projects.

4.0.3 — Southern Route Risk Factors

PJM also engaged independent consultants to evaluate the constructability of overhead and submarine 230 kV transmission from Artificial Island to the existing Red Lion – Cedar Creek 230 kV line on the Delmarva Peninsula. Siting and permitting a new river crossing will be a major project schedule component.

Permitting and Agency Risk Factors

As with the northern route, PJM's consultant highlighted a number of on-land and Delaware River crossing transmission risks as summarized earlier in **Section 4.0.1**. Southern route permitting would be required by the United States Army Corp of Engineers who would likely coordinate review among most agencies from whom approval would be needed. From an on-land transmission construction risk perspective, however, Delaware's DNREC project review will likely give increased scrutiny to the impact to Highway 9, a narrow two-lane road classified as a "Coastal Heritage Scenic Byway" by the State of Delaware. At the very least, this highway designation could add to the level of public opposition.

Augustine Wildlife Area

The Augustine Wildlife Area is owned by DNREC Division of Fish and Wildlife. If the area cannot be avoided through route selection, a permit will be required. Acquiring easements on state public lands – conservation easements, wetland restoration sites and wildlife management areas – typically involves multiple reviews and coordination between state environmental and real estate divisions. Obtaining a permit for Augustine Wildlife Area could be difficult if other viable alternatives exist.

Submarine Construction Challenges

A Delaware River submarine cable crossing poses unique construction challenges. The cable will require a depth of 25 feet below the river bottom within the shipping channel, as noted in discussions with the Army Corps of Engineers. PJM's consultants noted, however, that with proper consultation with the Coast Guard and other regulatory agencies, shipping channel issues associated with such normal waterway activities as fishing, anchors and other new river installations should be minimized.

Consultant reports also cited recent experience with dredging projects against which much public opposition was raised and many legal challenges were mounted. Opponents drew attention to potential river bottom ecosystem and water quality issues caused by cable installation, particularly that caused by jet-plowing techniques. Horizontal directional drilling installation techniques, in contrast, may mitigate these concerns.

Horizontal Directional Drilling

Unlike jet-plowing techniques, which impact the riverbed over the length of the installation, horizontal directional drilling impacts will be limited to the area associated with two coffer dams within the river, greatly reducing the disturbance area. Horizontal directional drilling employs a long, flexible drill bit to bore horizontally underground. This technology is a trench-less method in which no surface excavation is required except for drill entry and exit points. This minimizes surface restoration to a fraction of that associated with installations completed with open-cutting and associated ecological disturbances and environmental impacts.

Utilizing horizontal drilling is less likely to require a National Environmental Policy Act (NEPA) Environmental Impact Statement (EIS).

Notwithstanding the potential permitting issues identified, consultants suggested that the temporary disruption of Delaware River habitats as a result of submarine cable installation is preferable to the ongoing permanent disruption caused by overhead transmission river crossings and associated tower structures.

4.0.4 — SVC Device Constructability Analysis

PJM's technical analysis indicated that a SVC device located at Artificial Island performed marginally better than one located at New Freedom or Orchard substations. Consultant expertise was engaged to contrast the constructability risks of the proposed locations. Based on their analyses, PJM determined that the project complexities of installing an SVC device at Artificial Island outweighed marginal performance gains over the New Freedom 500 kV substation.

4.0.5 — Constructability Observations

Several key observations have guided PJM Artificial Island solution development:

- A solution that can mitigate permitting is preferred, particularly in such areas as the Supawna Meadows National Wildlife Refuge (impacted by the 500 kV Red Lion-Hope Creek transmission line proposal) and the Augustine Wildlife Area (impacted by 230 kV southern transmission line proposals). Permitting agencies would not state the likelihood of project permitting success without detailed design and route information in hand. They did note, however, that permitting through the sensitive Supawna Meadows National Wildlife Refuge and Augustine Wildlife Area could be more difficult if other viable alternatives were available.

- Siting and permitting for a new river crossing will be a major project schedule component under all proposals. Lower risk appears to exist for solutions that utilize horizontal directional drilling to minimize environmental impacts.

Section 5 – Cost Commitment Evaluation

5.0: Cost Commitment Evaluation

5.0.1 — Cost Estimate Submittals

Transmission project construction costs are influenced by many factors. The Artificial Island proposals are no exception. Cost estimates submitted to PJM addressed line routing, siting and permitting, environmental remediation, engineering, material procurement, line construction, expansion of existing substations, project management and contingency.

Initial Cost Estimates

Seven different sponsors submitted 26 separate proposal packages during the Artificial Island Window. Cost estimates ranged from approximately $100 million to $1.55 billion and reflected a diverse range of technologies at both 500 kV and 230 kV. Utilizing input from previous RTEP projects and consultant expertise, PJM developed cost estimates that permitted a more level-playing-field comparison.

Supplemental Project Information

In July 2014, LS Power submitted a cost commitment of $146 million for all costs for its proposed 230 kV transmission line and new substation in Delaware. At its July 2014 meeting, the PJM Board reviewed PJM's technical and constructability evaluation to that point, as well as LS Power's proposed cost commitment. In light of LS Power's submittal, the PJM Board directed PJM to allow PSE&G, Transource Energy and Dominion the opportunity to supplement their proposals as well. The PJM Board did reiterate, however, that cost was only one among a number of considerations that would guide its Artificial Island solution decision. Among the four finalists, LS Power, Transource and PSE&G elected to provide a cost commitment or cost containment mechanism.

LS Power Cost Commitment Summary

The LS Power cost commitment for the 230 kV line between Salem substation and the 230 kV right-of-way in Delaware and for the new substation in Delaware included the costs for the items below:

- Obtaining permits and other governmental approvals;
- Acquiring land and land rights
- Performing environmental assessments or mitigation activities
- Design and engineering
- Procurement of equipment, supplies and materials
- All other development and construction-related activities – e.g. site clearing, equipment assembly and erection, testing and commissioning
- Applied to overhead, submarine or horizontal directional drilling river crossing alternatives

Costs excluded from the LS Power commitment included the following:

- Escalation, taxes, and financing (e.g. AFUDC) costs. Escalation of the cost commitment would be tied to an industry standard index.
- Additions and modifications to the project scope due to:
  - Material change in the enforcement, interpretation of application of any statue, rule, regulation, order or other applicable existing law
  - Breach or default by PJM of its obligations under the Designated Entity Agreement
  - Request by PJM to delay or suspend project activities
  - Breach, default, interference or failure to cooperate by any Transmission Owner in connection with the Interconnection Coordination Agreement or interconnection agreement
  - Ongoing project maintenance and operations costs.

LS Power affirmed that the scope of work included all activities required to achieve an overhead or submarine crossing of the Delaware River.

PSE&G Cost Commitment Summary

PSE&G proposed an *in-service year* cost commitment of $221 million. The scope of work under the commitment comprised the 500 kV line between Hope Creek and Red Lion substations and the upgrades required at the Hope Creek substation. PSE&G indicated that the cost commitment included all project costs, with exceptions as noted below:

- Costs associated with PJM modifications or additions to the scope of work
- Costs incurred from the following events deemed outside of the control of PSE&G:
    - Changes in applicable laws and regulations
    - Obtaining governmental approvals and permits
    - Obtaining necessary property rights
    - Environmental permitting, remediation and mitigation
    - Orders of courts or action or inaction by governmental agencies

Transource Cost Commitment Summary

Transource provided a cost containment mechanism in which it would forego certain incentive rates if project costs exceeded certain thresholds. The scope of work under the mechanism included the 230 kV line and the new substations – one in Delaware and the other adjacent to or near the Salem substation. The work at Salem substation and on the right-of-way in Delaware required to connect the new substations would not be under the mechanism. The proposed tier levels and incentive rate changes are summarized below:

- Up to $243 million
    - Entitled to recover all FERC-approved ROE plus incentives
- Portion from $243 to $299.8 million
    - Forego 50 percent of any FERC-approved ROE incentives
- Above $299.8 million
    - Forego 100 percent of any FERC-approved ROE incentives

5.0.2 — Cost Commitment Evaluation

Subsequent to the July 2014 PJM Board meeting, PJM factored into its evaluation the supplemental project cost information submitted by PSE&G, Transource Energy, LS Power and Dominion. PJM enlisted the assistance of third party consultant expertise to assess the validity of the submitted estimates and to support the development of additional cost estimates where required.

Comparing Cost Commitments

Figure 5.1 provides a cost commitment comparison. The estimates couple the Proposing Entity's cost commitment numbers with PJM's own cost estimates for those elements that were not provided: expansion of existing substations and additional solution elements identified by PJM to satisfy requirements of the solicitation. Total project cost estimates were derived from the components described below.

- *Cost commitment* estimates were provided by PSE&G, Transource Energy and LS Power for the transmission facility elements included in their respective supplemental submittals. Dominion did not provide a cost containment value.
- *Upgrade project elements* capture the cost of the Transmission Owner work required to accommodate the proposed line.
- *Optical Ground Wire (OPGW)* installation for proposals Transource-2B and LS Power-5A is estimated to cost $25 million. That estimate is reduced to $20 million for proposals Dominion – 1C and PSE&G-7K given that certain OPGW costs would be included in the cost for the Hope Creek to Red Lion Line construction.
- *Generator Step-Up (GSU) Transformer tap settings* can be changed at minimal additional cost and were not a determining cost factor.
- *SVC Device* installation for each proposal is estimated by PJM to cost between $31 and $38 million based on input from PJM's consultants.

Figure 5.1: Cost Commitment Comparison

	Dominion 1C Hope Creek - Red Lion 500 kV Line ($M)	Transource 2B 230 kV Submarine Line ($M)	LS Power 5A 230 kV Submarine Line ($M)	PSE&G Hope Creek - Red Lion 500 kV Line ($M)
Cost Containment (Per Supplemental Proposals)	n/a	$203 - $259	$146	$221
Project Cost Estimate (Where Not Provided)	$211 - $257	n/a	n/a	n/a
Additional Proposal Elements:				
· New Salem Substation	n/a	$41	n/a	n/a
· Existing Salem Substation Expansion	n/a	$14 - $17	$61 - $74	n/a
· Existing Red Lion Substation Expansion	n/a	n/a	n/a	$4 - $6
OPGW / GSU Taps	$20	$25	$25	$20
SVC Cost Estimate	$31 - $38	$31 - $38	$31 - $38	$31 - $38
Project Capital Cost Total Estimate *Current Year Dollars*	**$263 - $316**	**$313 - $380**	**$263 - $283**	**$277 - $285**
Project Capital Cost Total Estimate *Future Year Dollars*	**$284 - $341**	**$346 - $411**	**$284 - $306**	**$281 - $290**

Capital Cost Total Estimates

PJM developed a *Project Capital Cost Total Estimate* for each proposal in both *current- year* dollars and *in-service year* dollars, given that PSE&G provided their cost commitment numbers in terms of in-service year dollars. In order to compare the costs on a common basis, PJM applied an escalation factor to the other three proposals at 2.5 percent per year. PJM selected 2.5 percent based on historical data from various resources, including the Bureau of Labor Statistics and PJM's Cost Development Subcommittee.

Note:

We note that on July 24, 2015, PSE&G submitted a modification to its proposal. This late-filed submission came too late in the process to afford all stakeholders due process and an opportunity to review the revised proposal. As a result, it was not considered as a timely modification of PSE&G's proposal. However, even if PJM had considered the latest PSE&G modification, it does not modify the PJM staff's recommendation since PSE&G has still left uncapped a potentially significant level of environmental mitigation costs, which could well occur under its proposal.

5.0.3 — Cost Commitment Observations

Key cost commitment observations that influenced PJM's Artificial Island solution recommendation included the following:

- Proposals Transource-2B and Dominion 1C have higher estimated costs relative to proposals PSE&G-7K and LS Power-5A,

- PJM evaluated the proposed cost commitments and found that LS Power's terms and conditions provide fewer exclusions than those proposed by PSE&G. PJM considered the potential magnitude of the cost impact of the proposed non-standard terms and conditions that address exclusions to the cost commitments provided by LS Power and PSE&G. Risks considered were the potential for route change, for schedule delays and for additional costs associated with environmental mitigation. As a result, PSE&G's proposal shows greater potential for increased costs. When considering the potential cost of such factors, the net effect is a further overlapping of the range, from low to high, of the total cost estimates for the two projects.

Section 6 – Recommended Solution & Next Steps

6.0: Recommended Solution and Next Steps

6.0.1 — Recommendation to the PJM Board

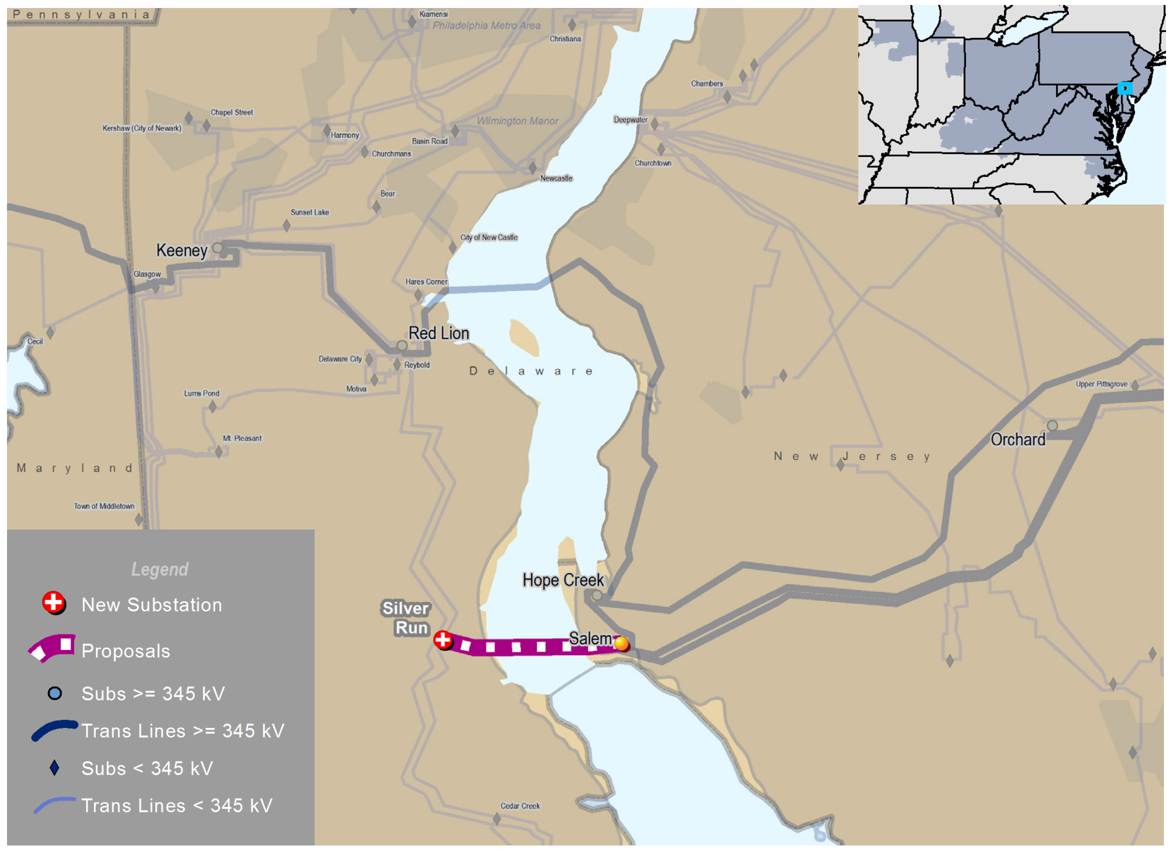
Each project offers certain advantages and risks with regard to performance, cost commitment and constructability. However, based on its technical analysis and constructability assessments, PJM staff is recommending the following projects to the Board because they represent the best balanced solution that both satisfies the technical performance requirements and provides a constructible solution with reasonable cost commitment.

New 230 kV Transmission Line Delaware River Crossing

A new 230 kV transmission line to be designated to LS Power should be constructed under the Delaware River from Salem to a new substation in Delaware that would tap the existing Red Lion - Carranza and Red Lion - Cedar Creek 230 kV lines, as shown on **Map 6.1**. Associated substation work at Salem would be designated to PSE&G and associated work on the 230 kV right-of-way in Delaware would be designated to Pepco Holdings, Inc. (PHI).

The LS Power proposal provides greater cost certainty with fewer exclusions to its cost commitment. From a constructability perspective, utilizing horizontal directional drilling techniques could mitigate siting and permitting risks.

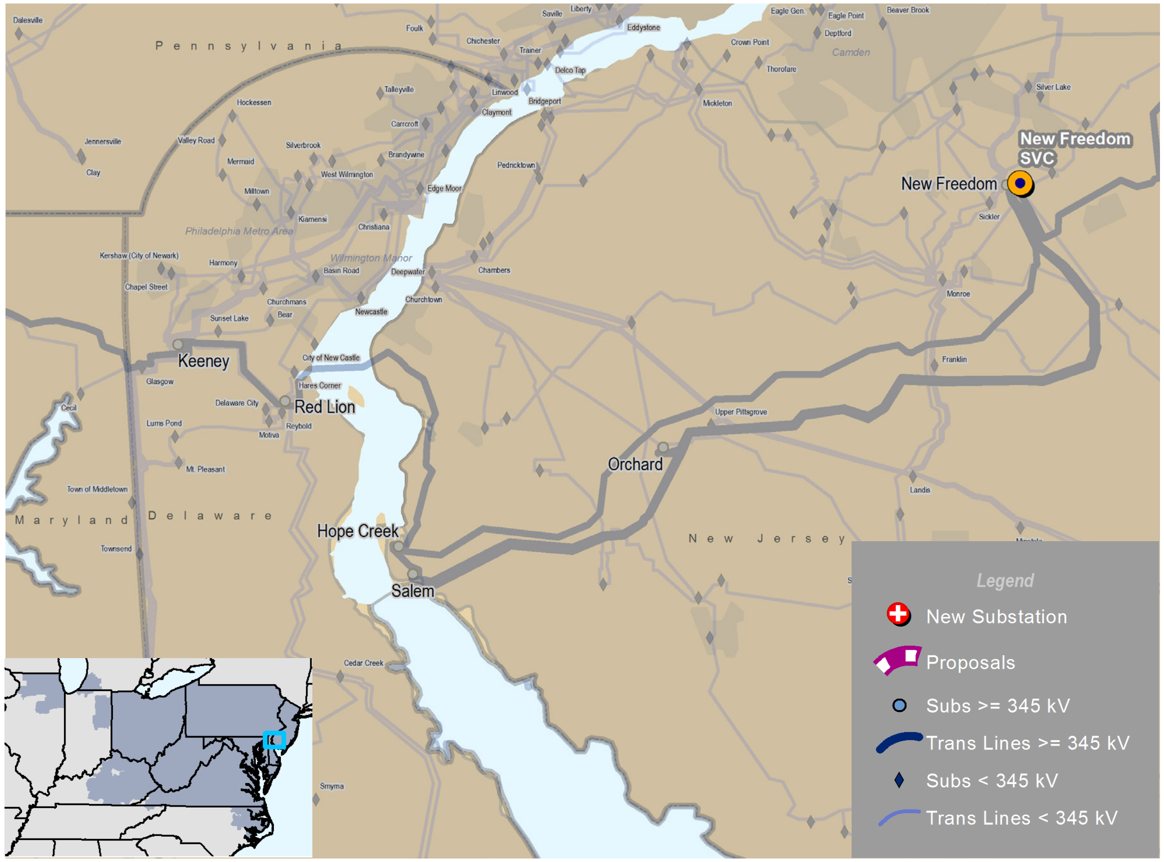
Map 6.1: New 230 kV Transmission Line Delaware River Crossing



New Freedom 300 MVAR SVC Device

A new 300 MVAR SVC device should be constructed at the New Freedom 500 kV substation, shown on **Map 6.2**, and designated to PSE&G. When compared to the simulations without an SVC device, proposals with SVC devices provided better voltage and machine MVAR response at Artificial Island, correlating to better post-fault system stability operational performance as sought by PJM's request for proposal.

Map 6.2: New Freedom 300 MVAR SVC Device



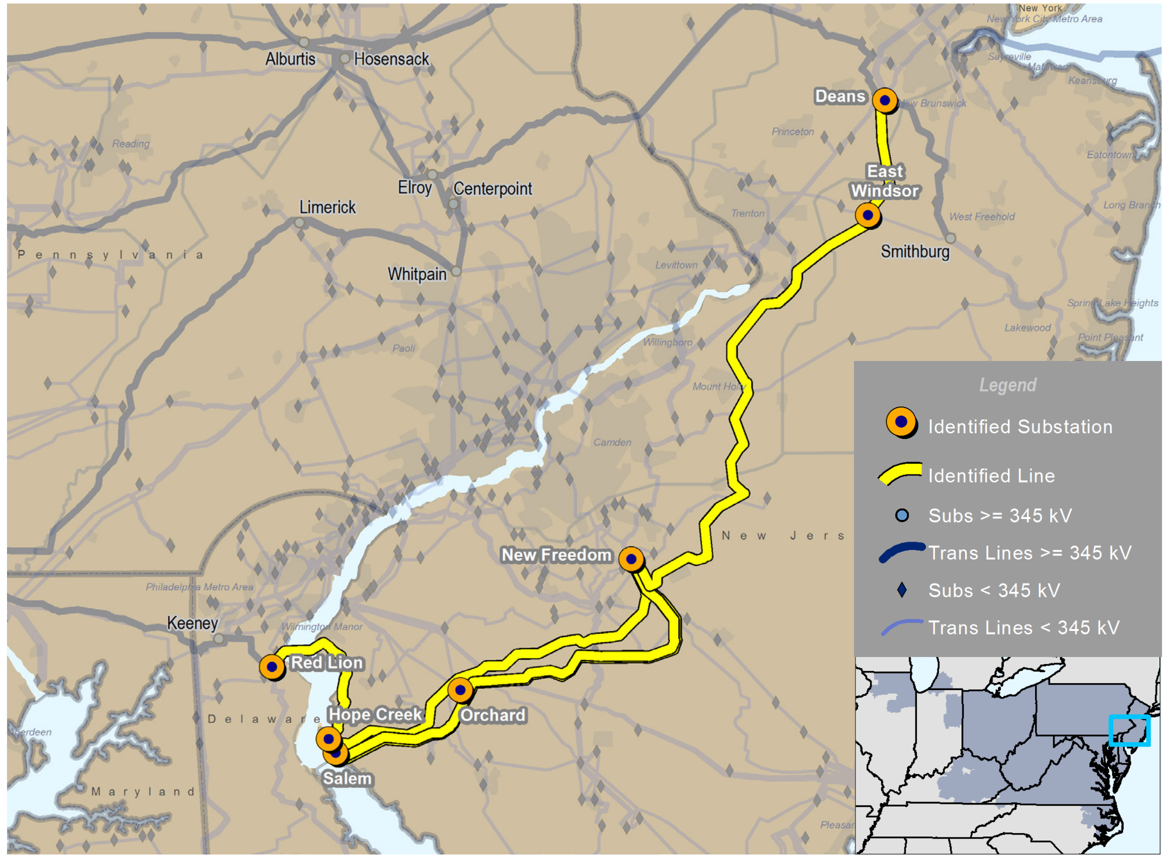
High Speed Optical Ground Wire Communications

High speed relaying utilizing optical ground wire (OPGW) communications should be added to the protection systems of a number of critical 500 kV circuits in the vicinity of Artificial Island, listed below and shown on **Map 6.3**, to provide faster fault clearing times, thereby providing additional stability margin:

- Hope Creek - Red Lion (operational designation 5015)
- Salem - Orchard (5021)
- East Windsor - Deans (5022)
- Hope Creek - New Freedom (5023)
- Salem - New Freedom (5024)
- Salem - Hope Creek Line (5037)
- New Freedom - East Windsor (5038)
- New Freedom - Orchard (5039)

Doing so would improve the operational performance sought by PJM's request for proposal. OPGW upgrades to these facilities would be designated to PSE&G, PHI and FirstEnergy accordingly.

Map 6.3: 500 kV Lines for Optical Ground Wire Communications



Artificial Island Generator Step-Up Transformer Tap Settings

Tap settings for the generator step-up transformers at the three Artificial Island units – Salem 1, Salem 2 and Hope Creek – should be changed, as designated to PSE&G. Doing so would improve the voltage control operational performance sought by PJM's request for proposal in accordance with NERC TPL Standards.

6.0.2 — Next Steps

If the PJM Board elects to approve the recommended solution, PJM staff will then notify LS Power that it has been assigned as the Designated Entity for the 230 transmission line portion of the solution. PJM will also draft the Designated Entity Agreement and Interconnection Coordination Agreements, which will detail the duties, accountabilities, obligations and responsibilities of each party. The terms of the Designated Entity Agreement will incorporate those presented by LS Power in documents posted publicly on PJM's website and shared with PJM stakeholders. Existing Transmission Owners with responsibility for portions of the recommended solution will be notified of their respective Designated Entity assignments as well.

Likewise, Board approval will include cost allocation identified by PJM consistent with the terms of the PJM's Operating Agreement and Open Access Transmission Tariff (OATT).

Designated Entity Agreement

When a project is designated as greenfield and not reserved for the Transmission Owner, a Designated Entity Agreement must be executed. The Designated Entity Agreement defines the terms, duties, accountabilities and obligations of each party, and relevant project information, including project milestones. Once construction is complete and the Designated Entity has met all Designated Entity Agreement requirements, the Agreement is no longer needed. The Designated Entity must execute the Consolidated Transmission Owners Agreement as a requirement for Designated Entity Agreement termination. Once a project is energized, a Designated Entity that is not already a Transmission Owner must become a Transmission Owner, subject to the Consolidated Transmission Owners Agreement.

Interconnection Coordination Agreement (ICA)

Because a Designated Entity may not qualify to be a party to the Consolidated Transmission Owners Agreement at the time the Designated Entity is selected, the execution of an Interconnection Coordination Agreement acts as a precursor to a wires-to-wires agreement between the interconnecting Transmission Owner and the Designated Entity. The Interconnection Coordination Agreement covers only coordination of construction prior to energizing the Designated Entity's project and defines the terms, duties, accountabilities and obligations of each party.

Cost Allocation

PJM is responsible for determining RTEP upgrade cost allocation, seeking PJM Board approval and filing those allocation percentages with the FERC under the terms of PJM's Operating Agreement, Schedule 6, and Open Access Transmission Tariff, Schedule 12. To that end, PJM has developed preliminary cost responsibility percentages – as shown in **Appendix 1** – for Artificial Island solution project elements whose costs will be allocated to multiple transmission zones. PJM notes that the aggregate total amount of the project to be assigned to the Delmarva transmission zone is $246.42 million, 89.46 percent of the total $275.45 million cost estimate. The remaining $29.03 million would be assigned to other transmission zones based on load ratio shares.

Appendix 1 – Preliminary Artificial Island Project Recommendation Cost Responsibility Percentages

Preliminary cost responsibility percentages are shown in the table below for Artificial Island solution project elements whose costs will be allocated to multiple transmission zones.

Baseline Upgrade ID	Description	Cost Estimate ($M)	Designated Entity	Cost Responsibility	Required In-service Date
b2633.1	Build a new 230 kV transmission line between Salem and Silver Run	$146.00	LS Power	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.2	Construct a new Silver Run 230 kV substation	*	LS Power	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.3	Install an SVC at New Freedom 500 kV substation	$34.45	PSE&G	AEC - 0.77%, AEP - 7.66%, APS - 2.94%, ATSI - 3.88%, BGE - 2.09%, COMED - 6.19%, ConEd - 0.29%, DAYTON - 1.01%, DEO&K - 1.61%, DL - 0.85%, DPL - 51.21%, DVP - 6.21%, ECP - 0.1%, EKPC - 1.08%, JCPL - 1.78%, ME - 0.89%, NEPTUNE - 0.21%, HTP - 0.10%, PECO - 2.59%, PENELEC - 0.96%, PEPCO - 1.99%, PPL - 2.53%, PSE&G - 2.99%, RE - 0.13%	4/1/2019
b2633.4	Add a new 500 kV bay at Salem (Expansion of Salem substation)	$7.35	PSE&G	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.5	Add a new 500/230 kV autotransformer at Salem	$60.65	PSE&G	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.6	Implement high speed relaying utilizing OPGW on Deans - East Windsor 500 kV and East Windsor - New Freedom 500 kV lines	$1.00	JCPL	AEC - 0.77%, AEP - 7.66%, APS - 2.94%, ATSI - 3.88%, BGE - 2.09%, COMED - 6.19%, ConEd - 0.29%, DAYTON - 1.01%, DEO&K - 1.61%, DL - 0.85%, DPL - 51.21%, DVP - 6.21%, ECP - 0.1%, EKPC - 1.08%, JCPL - 1.78%, ME - 0.89%, NEPTUNE - 0.21%, HTP - 0.10%, PECO - 2.59%, PENELEC - 0.96%, PEPCO - 1.99%, PPL - 2.53%, PSE&G - 2.99%, RE - 0.13%	4/1/2019

Baseline Upgrade ID	Description	Cost Estimate ($M)	Designated Entity	Cost Responsibility	Required In-service Date
b2633.7	Implement high speed relaying utilizing OPGW on Red Lion - Hope Creek 500 kV line	$0.50	DPL	AEC - 0.77%, AEP - 7.66%, APS - 2.94%, ATSI - 3.88%, BGE - 2.09%, COMED - 6.19%, ConEd - 0.29%, DAYTON - 1.01%, DEO&K - 1.61%, DL - 0.85%, DPL - 51.21%, DVP - 6.21%, ECP - 0.1%, EKPC - 1.08%, JCPL - 1.78%, ME - 0.89%, NEPTUNE - 0.21%, HTP - 0.10%, PECO - 2.59%, PENELEC - 0.96%, PEPCO - 1.99%, PPL - 2.53%, PSE&G - 2.99%, RE - 0.13%	4/1/2019
b2633.8	Implement high speed relaying utilizing OPGW on Salem - Orchard 500 kV, Hope Creek - New Freedom 500 kV, New Freedom - Salem 500 kV, Hope Creek - Salem 500 kV, and New Freedom - Orchard 500 kV lines	$23.50	PSE&G	AEC - 0.77%, AEP - 7.66%, APS - 2.94%, ATSI - 3.88%, BGE - 2.09%, COMED - 6.19%, ConEd - 0.29%, DAYTON - 1.01%, DEO&K - 1.61%, DL - 0.85%, DPL - 51.21%, DVP - 6.21%, ECP - 0.1%, EKPC - 1.08%, JCPL - 1.78%, ME - 0.89%, NEPTUNE - 0.21%, HTP - 0.10%, PECO - 2.59%, PENELEC - 0.96%, PEPCO - 1.99%, PPL - 2.53%, PSE&G - 2.99%, RE - 0.13%	4/1/2019
b2633.9	Implement changes to the tap settings for the three Artificial Island unit's step up transformers	~0.00	PSE&G	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.10	Interconnect the new Silver Run 230 kV substation with the existing Red Lion - Cartanza and Red Lion - Cedar Creek 230 kV lines	$2.00	DPL	DPL - 99.99%, JCPL - 0.01%	4/1/2019

*Note: Cost for the new Silver Run 230 kV substation is included in the $146 M estimate for upgrade b2633.1

Artificial Island White Paper Glossary

Term	Acronym	Definition
Bulk Electric System	BES	As defined by NERC and Reliability*First*, BES facilities include the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.
Consolidated Transmission Owners Agreement	CTOA	Signatories to the CTOA agree to (i) facilitate the coordination of planning and operation of their respective Transmission Facilities within the PJM Region; (ii) transfer certain planning and operating responsibilities to PJM; (iii) provide for regional transmission service pursuant to the PJM Tariff and subject to administration by PJM; and (iv) establish certain rights and obligations that will apply to the signatories and PJM. Any entity that: (i) owns, or, in the case of leased facilities, has rights equivalent to ownership in, Transmission Facilities; (ii) has in place all equipment and facilities necessary for safe and reliable operation of such Transmission Facilities as part of the PJM Region; and (iii) has committed to transfer functional control of its Transmission Facilities to PJM must become a Party to the CTOA.
Designated Entity Agreement	DEA	When a project is designated as a greenfield project that is not reserved for the Transmission Owner, a Designated Entity Agreement is required to be executed. The Designated Entity Agreement defines the terms, duties, accountabilities and obligations of each party, and relevant project information, including project milestones. Once construction is complete and the Designated Entity has met all Designated Entity Agreement requirements the Agreement is no longer needed. The Designated Entity must execute the Consolidated Transmission Owners Agreement as a requirement for Designated Entity Agreement termination. Once a project is energized, a Designated Entity that is not already a Transmission Owner must become a Transmission Owner, subject to the Consolidated Transmission Owners Agreement.
Generator Step-Up Transformer	GSU	A GSU transformer ‘steps-up’ generator power output voltage level to a suitable grid level voltage for transmission of electricity to load centers.
Good Utility Practice		Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region.
Horizontal Directional Drilling	HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. Horizontal directional drilling is a trench-less method in which no surface excavation is required except for drill entry and exit points, which minimizes surface restoration, ecological disturbances and environmental impacts. By contrast, jet-plowing techniques impact the riverbed over the length of the installation.
Interconnection Coordination Agreement	ICA	Because the Designated Entity may not qualify to be a party to the Consolidated Transmission Owners Agreement at the time the Designated Entity is selected, the execution of an Interconnection Coordination Agreement acts as a precursor to a wires-to-wires agreement between the interconnecting Transmission Owner and the Designated Entity. The Interconnection Coordination Agreement covers only coordination of construction prior to energizing the Designated Entity’s project and defines the terms, duties, accountabilities and obligations of each party.

Term	Acronym	Definition
Megavolt-ampere reactive	MVAR	Megavolt-ampere reactive. See "Reactive Power."
North American Electric Reliability Corporation	NERC	NERC is an international, independent, self-regulatory, not-for-profit organization, whose mission is to ensure the reliability of the bulk power system in North America.
North American Electric Reliability Corporation Transmission Planning Standards	NERC TPL	NERC transmission planning reliability standards establish system planning performance requirements within a defined planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.
Open Access Transmission Tariff	OATT	A FERC filed tariff specifying the terms of conditions under which PJM provides transmission service including how PJM carries out its generation and merchant transmission interconnection process.
Optical Grounding Wire Communications	OPGW	A type of fiber optic cable used in the construction of electric power transmission and distribution lines which combines the functions of grounding and communications
Reactive Power (expressed in MVAR)		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is expressed in megavars (MVAR).
Regional Transmission Expansion Plan	RTEP	The plan prepared by PJM pursuant to Schedule 6 of the PJM Operating Agreement for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.
Regional Transmission Organization	RTO	An independent, FERC-approved organization of sufficient regional scope, which coordinates the interstate movement of electricity under FERC-approved Tariffs by operating the transmission system and competitive wholesale electricity markets and ensuring reliability and efficiency through expansion planning and interregional coordination.
Reliability		A reliable bulk power system is one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity.
Reliability*First* Corporation		Reliability*First* is a not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. Reliability*First* was approved by the North American Electric Reliability Council (NERC) on January 1, 2006 to become one of eight Regional Reliability Councils in North America. Reliability*First* is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR) and the Mid-American Interconnected Network (MAIN) organizations
Right-of-Way	ROW	A corridor of land on which electric lines may be located. The transmission owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Static VAR Compensation	SVC	A SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.

Term	Acronym	Definition
Sub-Synchronous Resonance	SSR	Power system sub-synchronous resonance (SSR) is the build-up of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, even catastrophic loss. The term "sub-synchronous" refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles-per-second).
System Stability		Stability studies examine the grid's ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause a nearby generator's rotor's position to change in relation to the stator's magnetic field, affecting the generator's ability to maintain synchronism with the grid. Power system engineers measure this stability in terms of generator bus voltage and maximum observed angular displacement between a generator's rotor axis and the stator magnetic field. Stability in actual operations is affected by machine MW, system voltage, machine voltage, duration of the disturbance and by system impedance. Transient stability examines this phenomenon over the first several seconds following a system disturbance.
Thyristor Controlled Series Compensation	TCSC	A TCSC device comprises a series capacitor bank shunted by a bidirectional thyristor valve in series with an inductor. This combination of devices is used to lower the apparent line impedance resulting in increased power transfer capability. A TCSC makes a long transmission line act like a much shorter transmission
Transmission Expansion Advisory Committee	TEAC	A committee established by PJM to provide advice and recommendations to aid in the development of the Regional Transmission Expansion Plan.
Transmission System		The transmission facilities operated by PJM used to provide transmission services. These facilities that transmit electricity: are within the PJM region; meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and have been demonstrated to the satisfaction of PJM to be integrated with the transmission system of PJM and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.
Transmission Owner		A PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a transmission owner.

AI Complaint Appendix 3: Letters to PJM Board

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DEPARTMENT OF STATE
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July 15, 2014

Mr. Howard Schneider
Chair, PJM Board
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

Mr. Terry Boston
President and CEO
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

RE: PJM Staff Recommendation to the Board Regarding Artificial Island

Dear Messrs. Schneider and Boston:

The Delaware Division of the Public Advocate ("DDPA") wholeheartedly endorses PJM Transmission Planning Staff's recommendation to construct a 500kV transmission from Hope Creek to Red Lion and a SVC at New Freedom. Consequently, we urge you and the PJM Board to approve the project at your Board meeting on July 22.

The DDPA vigorously opposed the two proposals that involved constructing a 230kV line through the State of Delaware. We believed, and continue to do so, that the 230kV proposals placed an unfair and undue burden on Delaware ratepayers because even though other states would have benefited from the construction of the line, the costs would be borne solely by Delaware ratepayers.

We appreciate PJM Staff's consideration and through review of all the Artificial Island proposals, and we pleased at the outcome of the process.

Again, we support the speedy approval of PJM Staff's recommendation.

Very truly yours,

David L. Bonar,
Public Advocate

STATE OF DELAWARE
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May 26, 2015

VIA ELECTRONIC DELIVERY

Mr. Howard Schneider
Chair, PJM Board of Managers
PJM Interconnection
PO Box 1525
Southeastern, PA 19399-1525

Re: **COMMENTS OF DELAWARE PUBLIC SERVICE COMMISSION REGARDING TRANSMISSION EXPANSION ADVISORY COMMITTEE ("TEAC") RECOMMENDATION FOR ARTIFICIAL ISLAND FACILITIES**

Dear Mr. Schneider,

At the April 28, 2015 TEAC meeting the PJM Staff provided its recommendation of the proposals to improve operational performance issues identified at Artificial Island ("AI") under a range of anticipated system conditions and to eliminate potential planning criteria violations (e.g., NERC, RFC, etc.) in the AI area. As requested at that meeting, the Delaware Public Service Commission ("Delaware PSC") hereby submits these comments regarding that recommendation. The Delaware PSC recognizes and appreciates that the ultimate decisions by the PJM Board regarding AI will be predominantly based on appropriate engineering and system reliability requirements. The Delaware PSC also recognizes and appreciates PJM's efforts in the extensive proposal window process to address and resolve the issues reflected in the AI operational difficulties. The Delaware PSC supports PJM's project recommendation and recognizes it offers not only system benefit, but also additional transmission support on the Delmarva Peninsula. However, as discussed further below, the Delaware PSC has significant concerns with the potential cost allocation impacts illustrated at recent TEAC meetings.

As an initial matter, it is important for the PJM Board to understand that the Delaware PSC recognizes and does not intend to disturb the cost allocation methodology in PJM's Tariff as approved by the FERC and included in PJM Manuals. However, to the extent that the cost allocation procedures are intended to recognize beneficiaries of transmission facilities, the Delaware PSC suggests that rationale is deficient in this case. The Delaware PSC would recommend to the PJM Board that there are unique, specific, and objectively determinable circumstances in this case that would justify additional studies to appropriately allocate costs consistent with the beneficiaries of the new facilities.

In response to the Regional Transmission Expansion Plan ("RTEP") proposal window initiated by PJM to address the AI stability issues on April 29, 2013, there were 26 proposed solutions submitted and evaluated by the TEAC. There was a range of costs from $100 million to $1.550 billion and included 500kV and 230kV facilities as well as new transformation, substations, and additional circuit breakers. The proposals provided a diversity of station connections, a variety of routing options, project risks, resource requirements, and timelines. The Delaware PSC monitored the TEAC meetings and certainly appreciates the complexity required in the evaluation to reduce the proposals to a final recommendation. PJM staff will recommend to the Board for inclusion in the RTEP a new 230kV circuit from Salem to a new substation near the 230kV corridor in Delaware tapping the existing Red Lion to Cartanza and Red Lion to Cedar Creek 230 kV lines, utilizing Horizontal Directional Drilling under the river ("LS Power 5a").

The Delaware PSC has not performed an independent analysis of the PJM staff final recommendations and takes no position at this time regarding the technical characteristics of the LS Power 5A (and supporting connection facilities). However, as presented by PJM staff, the LS Power 5A appears to provide both technical and economic benefits to the Delmarva zone. As discussed further below, however, the Delaware PSC has significant concerns regarding the ultimate cost responsibilities of PJM staff's final recommendations.

In response to a request from the Delaware PSC Staff, at the May 8, 2014 TEAC meeting PJM provided examples of cost responsibility for a Load Ratio Share and a DFAX allocation. As shown on slide 37 of that presentation[1] for a 500kV facility, Delmarva Power & Light Company ("Delmarva") was responsible for approximately 4.5% of the cost. The major responsibilities for the DFAX allocation of a 500kV facility included JCPL at approximately 51%. While the Delaware PSC takes no position at this time on the DFAX percentages shown in the example, the responsibilities appear logical in that cost responsibility is shared mainly among the entities in the New Jersey and Delaware transmission zones.

On the other hand, the cost allocation example for a 230kV facility such as the LS Power 5A displayed neither logic nor fairness. As shown on slide 38 of the May 8 TEAC presentation, the Delmarva zone would be assigned 100% of the cost for such a facility. It is not clear to the Delaware PSC why such a dramatic difference could occur in cost responsibility for a facility where the benefit of the project is to alleviate an operational problem in the New Jersey transmission zone and is the same for both facilities, yet the cost responsibility for the 230kV facility is assigned solely to the Delmarva transmission zone.

The Delaware PSC Staff estimates that the ultimate cost impact for the LS Power 5A and other AI facilities could be significant to Delaware transmission customers, including ratepayers of Delmarva.[2] Depending on the ultimate in-service costs of the LS Power 5A and other AI facilities, the cost impact could be nearly a 25% increase in Annual Transmission Revenue Requirements. Based on the last Annual Update filed by Delmarva, the Network Service Revenue

[1] "May 8 TEAC presentation" http://www.pjm.com/~/media/committees-groups/committees/teac/20140508/20140508-item-01-reliability-analysis-update.ashx

[2] The Delaware PSC additionally recognizes that the cost impact would also affect ratepayers of Old Dominion Electric Coop and the Delaware Municipal Electric Corporation.

Requirement for transmission service(s) effective June 1, 2014 was approximately $121 million.[3] Should the in-service costs for the LS Power 5A and other AI facilities assigned to Delmarva be estimated at $200 million with a conservative 15% carrying charge, the impact on the current Network Service Revenue Requirement for Delmarva transmission service(s) would be $30 million resulting in an increase of approximately 25%. In the view of the Delaware PSC, such an outcome is neither fair nor equitable and the resulting rate for transmission service(s) paid by Delmarva customers would not be just and reasonable.

What should be considered in this unique case is an appropriate assessment of the AI facilities that would reflect the benefits before and after construction of the new LS Power 5A. For example, when evaluating reliability projects for future periods, it appears that PJM's evaluations of costs and benefits of advancing reliability projects do contemplate such assessments. PJM Manual 14B: PJM Region Transmission Planning Process ("M-14B") provides as follows:[4]

> **2.6.4 Evaluation of cost / benefit of advancing reliability projects**
> PJM will perform annual market simulations and produce cost / benefit analysis of advancing reliability projects. An initial set of simulations will be conducted for current year plus 1 and current year plus 5 using the "as is" transmission network topology without modeling future RTEP upgrades. A second set of simulations will be conducted for each year using the as planned RTEP upgrades. A comparison of the "as is" and "as planned" simulations will identify constraints which have caused significant historical or simulated congestion costs but for which an as-planned upgrade will eliminate or relieve the congestion costs to the point that the constraint is no longer an economic concern.

On the other hand, it appears that PJM's baseline reliability upgrade cost allocation procedures do not include an assessment and comparison of "as is" and "as planned" simulations. PJM's M-14B provides as follows:

> **A.3 Schedule 12 Cost Allocation Process for Baseline Transmission Reliability Upgrades** . . . Allocation of transmission upgrades for reliability is beneficiary based. With respect to reliability projects, while a definitive benefit is from the elimination of a reliability criteria violation, the benefit quantified for the purpose of cost allocation is the use of the upgrade by PJM load zones. The usage of the reliability project by a PJM load zone relative to the usage by all other PJM load zones will be used to determine the percentage cost responsibility to be assigned to the zone.
>
> **A.3.1 RTEP Baseline Reliability Upgrade Cost Allocation** . . . Under this approach to cost allocation, it is entirely possible, and certainly consistent with the allocation philosophy, that the costs of upgrades in one transmission zone may be allocated in significant part to load in other transmission zones. While many required transmission upgrades are allocated entirely to load within the same zone where the criteria violation and the related upgrade are located, the nature of large, integrated transmission systems like the PJM system is such that transmission facilities in one area can be used

[3] FERC Docket No. ER09-1158 annual update filing May 15, 2014
http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14216771
[4] The Delaware PSC "assumes" that the identification and relief of constraints would be similar to the identification and relief of the operational difficulties encountered at AI.

significantly to serve loads in other areas. The planning process identifies the most effective solutions to criteria violations and the resultant use of these solutions by loads may not be related to the physical location of the transmission upgrade. Therefore, responsibility for the costs of baseline reliability upgrades likewise shall be allocated to those who use these solutions, regardless of their physical location relative to the location of the baseline reliability upgrade required to ensure the reliability of their service.

As shown above, when evaluating reliability upgrades for future periods there is a specific comparison between "as is" and "as planned" facilities which does not occur when determining the cost allocation process for reliability projects. While PJM Staff recognized, in M-14B section A.3.1 above, that one zone's required transmission reliability upgrades could be allocated to an entirely different zone based on load flows, they offered no potential mitigation for this issue. In this unique case, it would appear that in order to identify potential beneficiaries of new facilities, there should be assessments of "as is" of the existing AI facilities as well as "as planned" with the construction of the LS Power 5A.

Another example of potential beneficiaries of the LS Power 5A project, which is neglected in the current load flow cost allocation would be the expected improved system conditions that would allow maximum power output from all of the AI generation units without operational complexity. These assessments of limited generation operations with existing facilities compared to increased generation operations from all of the AI units after the installation of LS Power 5A should reflect the objectives of the original AI proposal window problem statement & requirements document as follows:[5]

1. Generate maximum power (3818 MW total) from all AI Units (Salem1: 1253MW, Salem-2: 1245MW, Hope Creek: 1320MW) without a minimum MVAr requirement from the AI. Full maximum power must be maintained under both the baseline and all N-1 outage conditions of 500kV transmission lines in the AI area. For both the baseline and N-1 outage conditions, AI voltage must be maintained within operating limits and stable for all NERC Category B and C contingencies. NERC Category C3 contingencies "N-1-1 contingencies" do not need to be run on top of the N-1 outage condition.
2. Maximum MW output from AI should not be affected by the simultaneous outage of Power System Stabilizers (PSS) of Artificial Island units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios.
3. Reduce operational complexity.
4. Improve Artificial Island stability.
5. Maintain PJM System Operating Limits (SOLs)

While these are the obvious benefits sought by PJM, there is no recognition of these benefits within the current cost allocation process. In the current allocation, enhanced New Jersey generation options, and generation company revenues, are predominantly paid by Delaware and Maryland rate payers. It does not appear that PJM has previously identified such benefits from enhanced operation of all of the AI generation units.

[5] http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/redacted-artificial-island-problem-statement.ashx

Another example in M-14B where the identification of beneficiaries versus cost recovery does not appear consistent with the proposed cost responsibility of LS Power 5A is shown in section 2.5 as follows:

> **2.5 RTEP Cost Responsibility for Required Enhancements**
> . . . The cost responsibility for each baseline-revealed Network Reinforcement is borne by transmission owners based on the contribution to the need for the network reinforcement.

While the AI Area Network includes some Delmarva transmission facilities, it is not clear that those Delmarva facilities solely contributed to the need for the network reinforcement to address the operational complexity, stability issues, or other concerns with the operation of the AI generation units. PJM has not identified, to this point, the extent to which the Delmarva transmission facilities included in the AI Area Network supports the cost allocation proposed for the LS Power 5A.

The Delaware PSC requests that PJM perform the necessary simulations to identify the beneficiaries of the AI facilities before and after the construction of LS Power 5A through simulations of the "as is" and "as planned" facilities. The Delaware PSC suggests that reliance on a single DFAX of LS Power 5A showing just the usage of that new facility does not appropriately identify the beneficiaries of its construction and operation.

As mentioned previously, the Delaware PSC is not intending to protest PJM's procedures regarding the evaluation of RTEP upgrades. In this case, however, there are unique, specific, and objectively determinable circumstances that would justify additional studies to appropriately allocate costs consistent with the beneficiaries of the new facilities. There are three coincident circumstances, when all are occurring with a proposed RTEP upgrade, which PJM should consider to justify additional studies (simulations) to determine cost allocation as follows:

1. Construction of a new facility that also requires new right(s) of way in addition to new equipment; and

2. The DFAX of the new facility assigns all (or nearly all) of the costs to a transmission zone which is different than the zone where the evaluation of the costs and benefits of the new facility was considered; and

3. The cost allocation resulting from a single DFAX would significantly increase the rates paid by customers for transmission service(s).

Recognition of these three unique, specific and objectively determined circumstances when they all occur with a proposed RTEP upgrade would allow PJM to provide the necessary additional information to implement appropriate cost allocation of transmission facilities corresponding to the beneficiaries of the construction and operation of those transmission facilities.

The Delaware PSC recognizes that cost allocation is within the Transmission Owners realm of authority and is anxious to resolve this concern without a lengthy protracted FERC process. As the Delaware PSC perceives it, the proposed cost allocation is unjust and unreasonable without a legitimate correlation to benefit.

The PJM Board has previously shown leadership in the determination of the selection process for the Artificial Island proposals. At the July 2014 Board meeting, the PJM Board deferred selection for the Artificial Island project solution in order to obtain additional information concerning cost caps, scope of work, and project schedules which resulted in a final recommendation by PJM staff that was able to incorporate much needed material to support the approval of the LS Power 5A project now before the Board. The Delaware PSC would urge the PJM Board to continue its leadership in this matter and to include in its approval of the LS Power 5A project a requirement that PJM staff address and resolve the cost allocation issue as recommended in the above comments.

Please feel free to contact me or Mr. Robert Howatt our Executive Director, should you have any questions, or if I can be of further assistance in this matter.

Sincerely,

Dallas Winslow

Chairman
Delaware Public Service Commission

Copies:
Members, PJM Board
Mr. Craig Glazer, Vice President-Federal Government Policy, PJM
Mr. Steve Herling, PJM Vice President – Planning
Mr. Paul McGlynn, Chair, Transmission Expansion Advisory Committee
Commissioners, Delaware Public Service Commission
Mr. Robert Howatt, Executive Director, Delaware Public Service Commission
Ms. Janis Dillard, Deputy Director, Delaware Public Service Commission
Mr. David Bonar, Delaware Public Advocate

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May 27, 2015

VIA ELECTRONIC MAIL

Mr. Howard Schneider
Chair, PJM Board of Managers
PJM Interconnection, LLC
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Southeastern, PA 19399-1525

Re: **THE DELAWARE DIVISION OF THE PUBLIC ADVOCATE'S COMMENTS REGARDING THE PJM TRANSMISSION EXPANSION ADVISORY COMMITTEE'S ARTIFICIAL ISLAND**

Dear Mr. Schneider:

At the April 28, 2015 Transmission Expansion Advisory Committee meeting, PJM Staff advised that it would recommend that the PJM Board select (and include in the next Regional Transmission Expansion Plan) LS Power's proposed project (the "Project") to remedy operational performance issues and eliminate potential planning criteria violations (e.g., NERC, RFC, etc.) at Artificial Island ("AI"). The Project involves, among other things, constructing a new 230kV circuit from Salem to a new substation near the 230kV corridor in Delaware (using horizontal directional drilling under the Delaware River), tapping the existing Red Lion to Cartanza and Red Lion to Cedar Creek 230 kV lines LS Power estimates that the Project will cost in the range of $263 million to 283 million, and has agreed to cap the costs at that amount.

Under PJM's cost allocation procedures, the Delmarva Power & Light ("DP&L") transmission zone will be responsible for 99.99% of the costs of the 230 kV portion of the Project, and the Jersey Central Power & Light ("JCPL") will be responsible for only 0.01% of the costs of the 230 kV portion of the Project. Half of the allocation for the 500 kV portions will be socialized to New Jersey and the other half of the project will be allocated to DP&L and JCPL based on the 99.99%/0.01% split. The Delaware Division of the Public Advocate ("DPA") respectfully submits that allocating virtually the entire amount of the 230kV cost to the Delmarva transmission zone is neither logical nor fair.

The Project's purpose is to alleviate an operational problem in the New Jersey transmission zone, and the vast majority of Project stability benefits will accrue to the New Jersey transmission zone.[1] It is incontrovertible that the enhanced stability of Artificial Island will benefit New Jersey end users as well as residents of Delaware, Maryland and Virginia. If PJM's cost allocation

[1] PJM has identified the following Project benefits: (1) Generate maximum power (3818 MW total) from all AI Units (Salem-1: 1253MW; Salem-2: 1245MW; Hope Creek: 1320MW) without a minimum MVAr requirement

procedures are intended to recognize the beneficiaries of transmission facilities, *this* cost allocation – which ignores the fact that the New Jersey transmission zone is the predominant beneficiary of the Project - violates that intent. Further, the impact on Delaware ratepayers of the allocation of virtually 100% of Project costs to the Delmarva transmission zone is significant:[2] The Delaware Public Service Commission staff has calculated that the Annual Transmission Revenue Requirement for the Delmarva transmission zone could increase by nearly 25%.[3]

The DPA respectfully requests the PJM Board to consider the unique situation in which AI's reliability problems exist. We believe that PJM's procedures provide for such consideration. *See, e.g.*, PJM Manual 14B: PJM Region Transmission Planning Process, §2.6.4 ("Evaluation of cost/benefit of advancing reliability projects"); §A.3 Schedule 12. Furthermore, Manual 14B Section 1.3 Schedule 12 specifically states that "*[a]llocation of transmission upgrades for reliability is beneficiary based.*" (Emphasis added). Finally, Manual 14B §2.5 provides that "[t]he cost responsibility for each baseline-revealed Network Reinforcement is borne by transmission owners *based on the contribution to the need for the network reinforcement.*" (Emphasis added).

While the AI Area Network includes some Delmarva transmission facilities, it is clear that those facilities are not the sole reason for the network reinforcement contemplated in the Project. Indeed, PJM Staff has yet to identify to what extent (if any) the Delmarva transmission facilities included in the AI Area Network contributed to the need for the Project. What *is* clear, however, is that the Project is intended to remedy issues in the *New Jersey transmission zone. See supra* n.1.

The DPA is not suggesting that the Delmarva transmission zone should not be allocated any of the Project costs: to the contrary, the DPA acknowledges that the Project does provide some system benefits and additional transmission support on the Delaware peninsula. The DPA respectfully submits, however, that there is no logical or fair basis for allocating almost 100% of the costs of the Project to the Delmarva transmission zone. The PJM Board has exercised its independent judgment in previous considerations of what should be done to remedy the AI problems; the DPA asks that the Board of Managers reject PJM Staff's recommendation and direct Staff to seek an allocation that recognizes the benefits of the AI Project to all the affected entities in New Jersey,

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from AI. Maintaining full maximum power under both the baseline and all N-1 outage conditions of 500kV transmission lines in the AI area. Maintaining AI voltage within operating limits and stable for all NERC Category B and C contingencies. (2) Maximum MW output from AI should not be affected by the simultaneous outage of Power System Stabilizers (PSS) of AI units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios. (3) Reduce operational complexity. (4) Improve AI stability. (5) Maintain PJM System Operating Limits (SOLs). *See* http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/redacted-artificial-island-problem-statement.ashx

[2]Old Dominion Electric Cooperative and Delaware Municipal Electric Corporation ratepayers will also be affected by this cost allocation.

[3] Based on Delmarva Power & Light Company's most recent last Annual Update, the Network Service Revenue Requirement for transmission service(s) effective June 1, 2014 was approximately $121 million. If the in-service costs for the Project and other AI facilities are $200 million with a conservative 15% carrying charge, the impact on the current Network Service Revenue Requirement for Delmarva transmission service(s) would be $30 million, which is an approximate 25% increase.

Delaware, Maryland, Virginia and any other end users in other jurisdictions that may result from the stability benefits derived from this Project.

The DPA is available at your convenience should you wish to discuss this matter further.

Very truly yours,

David L. Bonar
Public Advocate for the State of Delaware

DLB/rai

cc: Members, PJM Board
Mr. Craig Glazer, Vice President-Federal Government Policy, PJM
Mr. Steven Herling, PJM Vice President – Planning
Mr. Paul McGlynn, Chair, Transmission Expansion Advisory Committee
Commissioners, Delaware Public Service Commission
Mr. David Anders, Director, PJM Stakeholder Affairs
Mr. Robert Howatt, Executive Director, Delaware Public Service Commission
Ms. Janis L. Dillard, Deputy Director, Delaware Public Service Commission

ODEC Old Dominion Electric Cooperative℠

May 29, 2015

VIA ELECTRONIC DELIVERY
Howard Schneider
Chair
Board of Managers
PJM Interconnection, L.L.C.
P.O. Box 1525
Southeastern, PA 19399-1525

Re: Comments of Old Dominion Electric Cooperative, A&N Electric Cooperative, Choptank Electric Cooperative and Delaware Electric Cooperative on PJM Staff Artificial Island Recommendation

Dear Mr. Schneider:

As requested at the April 28, 2015 meeting of the Transmission Expansion Advisory Committee ("TEAC"), Old Dominion Electric Cooperative, on behalf of itself and its Member Cooperatives serving customers on the Delmarva Peninsula, A&N Electric Cooperative, Choptank Electric Cooperative and Delaware Electric Cooperative (collectively, "ODEC") provides these comments regarding the PJM Staff's Artificial Island recommendation ("Recommended Proposal").

ODEC appreciates the hard work and analysis done by the Board and PJM Staff in evaluating the various Artificial Island proposals. Based on the information presented at the TEAC, it appears to ODEC that the Recommended Proposal could be a sound technical solution to address Artificial Island operational performance problems.

ODEC is very concerned, however, about the potentially disproportionate cost impact that implementation of the Recommended Proposal could have on customers located in the Delmarva Power & Light Company ("Delmarva") Transmission Zone, including ODEC. ODEC believes that additional analyses and information are needed to provide the Board and the PJM stakeholders a sufficient record to determine whether the Recommended Proposal is "the more efficient and cost-effective solution" and "avoid[s] the imposition of unreasonable costs on any Transmission Owner or any user of Transmission Facilities" as per sections 1.5.8(e) and 1.4(d)(ii), respectively, of Schedule 6 of the PJM Operating Agreement. Specifically, the Board should direct PJM Staff to develop the following information for stakeholder and Board review prior to a final decision:

- The projected cost allocation for each of the Artificial Island solutions considered in Staff's April 28 TEAC Presentation, including any assumptions made in determining the cost allocation.

- A detailed economic benefit analysis of the Recommended Proposal and the other proposals addressed by Staff in the April 28 Presentation, including, but not limited to, how much in market efficiency benefits are provided to each Transmission Zone from each of the proposals.

ODEC appreciates the evolutionary nature of this two-year assessment and the Board's sharp focus on this issue. ODEC strongly supports the planning principles and regional planning processes set forth under Orders 890 and 1000 and encourages the Board to make the additional time for PJM Staff to conduct these analyses and discuss them with the PJM stakeholders prior to a final Board decision.

Additionally, ODEC has reviewed the comments of the Delaware Public Service Commission ("Delaware PSC") on the Recommended Proposal and urges the Board to carefully consider the Delaware PSC's arguments as well and direct PJM Staff to provide the additional information the Delaware PSC requests.

Evaluation of the Recommended Proposal

In analyzing the various Artificial Island proposals, PJM Staff concluded that its Recommended Proposal incorporating LS Power's 230 kV underwater transmission line had the lowest projected cost based on current year dollars. *See* April 28 Presentation at 28. PJM Staff observed that a PSEG alternative incorporating a 500 kV line from Hope Creek to Red Lion ("PSEG 500 kV Alternative") might have a lower cost based on in-service year dollars, but had greater potential for increased costs due to exceptions in PSEG's cost containment proposal. *See* April 28 Presentation at 28, 38.

The April 28 Presentation indicates that, in analyzing the cost-effectiveness and reasonableness of the costs of the Artificial Island proposals, PJM Staff focused exclusively on the total project cost without giving due consideration to who would be paying those costs. Information from the May 8, 2014 TEAC meeting indicated 100 percent of the costs associated with LS Power's proposal would be allocated to the Delmarva Zone. In contrast, as a 500 kV project, 50% of the costs of the PSEG 500 kV Alternative would be allocated to all PJM Zones on a load ratio share basis and 50% of the costs would be allocated using DFAX. The costs of the PSEG 500 kV Alternative, therefore, would apparently be allocated much more broadly than the Recommended Proposal.

ODEC believes that, in this specific situation, the cost allocation of the proposed Artificial Island solutions is highly relevant to the determination of whether the proposal is "the more efficient and cost-effective solution" under section 1.5.8(e). Further, the potential disproportionate cost impact of the Recommended Proposal on a relatively small set of PJM customers should be considered in fulfilling the requirement under section 1.4(d)(ii) of Schedule 6 to "avoid the imposition of unreasonable costs on any Transmission Owner or any user of Transmission Facilities." At the least, the potentially disproportionate cost impact on the Delmarva Zone should be among the "other factors" PJM is entitled to consider under section 1.5.8(e) in evaluating whether to include a project in the RTEP.

In order to properly evaluate whether the Recommended Proposal, the PSEG 500 kV Alternative or some other proposal is "the more efficient and cost-effective solution" and whether costs would be unreasonably imposed on customers in the Delmarva Zone, the Board should direct the PJM Staff to calculate the projected cost allocation for each of the Artificial Island solutions and provide this information to the Board and all stakeholders.

Allocation of all or the majority of the Recommended Proposal costs to the Delmarva Zone would not necessarily mean that the Recommended Proposal is not "the more efficient and cost-effective solution" or that unreasonable costs are being imposed on customers in the Delmarva Zone. Although, as discussed below, ODEC does not believe that resolving the Artificial Island operational performance concerns alone would justify allocation of the large majority of the project costs to the Delmarva Zone, there may be other quantifiable benefits to the Delmarva Zone that conceivably could make the Recommended Proposal reasonable and cost-effective from the perspective of customers in the Delmarva Zone. For example, the April 28 Presentation (at slide 37) indicates that the Recommended Proposal would provide $92 million of market efficiency benefits over 15 years, while the PSEG 500 KV Alternative would provide $57 million of market efficiency benefits over the same period. The April 28 Presentation does not indicate, however, how these market efficiency benefits would be distributed in PJM.

Without information showing the economic benefits of the proposed solutions on a zonal basis, it is not possible to determine whether a proposed solution is cost-effective for the particular customers that could be required to pay for the solution. ODEC is not suggesting that this type of cost-benefit analysis should be conducted every time PJM Staff is making a choice between two potential transmission solutions, but in this case the additional analysis is justified given that numerous proposals are being evaluated to address operational performance criteria issues related to three specific generators and the cost estimates for the Recommended Proposal and the PSEG 500 kV Alternative are so similar.

Accordingly, the Board should direct PJM Staff to provide the Board and PJM stakeholders with a more detailed economic analysis of which Zones would receive market efficiency benefits from the Recommended Proposal and the other proposals addressed by Staff in the April 28 Presentation.

Disproportionate Allocation of Artificial Island Solution Costs to the Delmarva Zone

ODEC emphasizes that it is not taking a position at this time as to whether the Recommended Proposal or some other proposal is the appropriate solution for the Artificial Island operational performance problems. The information that ODEC requests above is necessary to make that determination. ODEC, however, would object to an Artificial Island solution that would be cost-allocated primarily to the Delmarva Zone without a showing that the proposed solution would provide some reasonable level of benefits to the Delmarva Zone.

In the original Artificial Island Proposal Window Problem Statement issued by PJM on April 29, 2013, PJM identified the following objectives for the Artificial Island solution:

1. Generate maximum power (3818 MW total) from all AI Units (Salem1: 1253MW, Salem-2: 1245MW, Hope Creek: 1320MW) without a minimum MVAr requirement from the AI. Full maximum power must be maintained under both the baseline and all N-1 outage conditions of 500kV transmission lines in the AI area. For both the baseline and N-1 outage conditions, AI voltage must be maintained within operating limits and stable for all NERC Category B and C contingencies. NERC Category C3 contingencies "N-1-1 contingencies" do not need to be run on top of the N-1 outage condition.
2. Maximum MW output from AI should not be affected by the simultaneous outage of Power System Stabilizers (PSS) of Artificial Island units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios.
3. Reduce operational complexity.
4. Improve Artificial Island stability.
5. Maintain PJM System Operating Limits (SOLs).

These objectives indicate that the primary purpose of the Artificial Island solution is to resolve generator stability and operational issues associated with the Salem and Hope Creek nuclear plants in southern New Jersey. Given this driver for the project, allocating all, or even a large majority, of the costs of the Artificial Island solution to customers in the Delmarva Zone would seem unreasonable. FERC and the courts have indicated that the costs of new transmission projects must be allocated commensurate with the benefits provided by the facilities. Even if customers in the Delmarva Zone benefit to some degree from the resolution of the southern New Jersey generator stability issues, allocating the majority of project costs to the Delmarva Zone would not be commensurate with any such benefits. Further, the Artificial Island solution apparently is intended to address primarily "operational performance" criteria, under which the relationship between the criteria violation and the use of the transmission facility solution may be more attenuated than, for example, a facility built to address a thermal criteria violation.

The unreasonableness of allocating the bulk of the Artificial Island solution costs to the Delmarva Zone without evidence of some additional benefits is also illustrated by the fact that, as discussed earlier, the costs of the PSEG 500 kV Alternative necessarily would be allocated to a broader set of customers. In other words, two transmission upgrades designed to address the same operational performance issues and both costing approximately the same would be allocated to widely varying groups of customers.

ODEC recognizes that Schedule 12 of the PJM Tariff contains specific cost allocation methods for RTEP projects. As a PJM Transmission Owner, ODEC participated in the development of these cost allocation methods, and ODEC has supported application of these methods to provide cost allocation certainty and promote transmission development in the PJM region. Further, ODEC agrees with PJM that cost allocation considerations should not drive planning decisions. In this situation, however, where several competing proposals are being specifically evaluated by PJM and stakeholders to address operational performance issues, with cost being a primary consideration, and where preliminary information indicates that the allocation of costs to the Delmarva Zone for the Artificial Island solution would have little relationship to either the project drivers or the benefits received by the Delmarva Zone from the solution, allocation based on application of the solution-based DFAX method could be unreasonable. ODEC notes in this respect that FERC is currently considering a number of challenges to solution-based DFAX cost allocations in particular situations. *See* FERC Docket

Nos. EL15-67-000, EL15-18-000, ER14-1485-000 and ER14-972-000. ODEC believes that questions similar to those raised in these FERC cases would need to be addressed if a substantial majority of the Artificial Island solution costs were to be allocated to the Delmarva Zone without some additional evidence of benefits.

Conclusion

ODEC is supportive of PJM's efforts to incorporate a competitive solicitation process in its regional plan. However, ODEC is concerned that a potentially disproportionate cost impact to customers in one zone absent a discernable benefit could adversely impact future competitive solicitations. Additional information from PJM is required to evaluate whether the Recommended Proposal is "the more efficient and cost-effective solution" to the Artificial Island operational performance problems and whether costs that Delmarva Zone customers would be allocated for the Recommended Proposal are reasonable and commensurate with the benefits that customers will receive from the project. The projected cost allocation information as well as the detailed economic analysis discussed above should provide an adequate record for decision-making.

The Board should direct PJM Staff to provide this information to the Board and stakeholders at least 30 days before the July 27, 2015 Board meeting, and the Board should allow for supplemental comments from stakeholders on this information. If necessary, the Board should defer selection of the Artificial Island solution to fully consider the requested information.

Without evidence of some additional benefit from the Recommended Proposal to the Delmarva Zone, however, the allocation of a substantial majority of the Recommended Proposal's cost to the Delmarva Zone would not be reasonable.

Sincerely yours,

Pete Bellini for

D. Richard Beam
Senior Vice President of Power Supply
Old Dominion Electric Cooperative

COMMISSIONERS

W. KEVIN HUGHES
CHAIRMAN

HAROLD D. WILLIAMS
LAWRENCE BRENNER
ANNE E. HOSKINS

STATE OF MARYLAND

PUBLIC SERVICE COMMISSION

June 5, 2015

VIA ELECTRONIC DELIVERY

Mr. Howard Schneider
Chair, Board of Managers
PJM Interconnection
955 Jefferson Avenue
Norristown, PA 19403

Re: PJM Artificial Island Transmission Project Selection

Dear Mr. Schneider:

On April 28, 2015, Staff of PJM Interconnection, L.L.C. ("PJM"), issued recommendations on what transmission enhancements should be made to resolve operational performance and planning criteria violations in the transmission network located at Artificial Island, New Jersey. PJM Staff will propose, for Managing Board approval on July 27, 2015, an LS Power proposed project ("Project") involving the construction of a 230 kV transmission line from Artificial Island across the Delaware River to a substation on the Delmarva Peninsula. The LS Power Project was selected in preference to a number of others that had been proposed during this two year analytical process.

Several letters have been filed with the Managing Board questioning PJM Staff's recommendation or its effect upon the transmission rates that will be allocated to Delmarva residents, including Maryland electricity consumer on the Peninsula. The Delaware Public Service Commission ("Delaware PSC"), for example, has stated that one result of the PJM Staff recommendation will be "a 25% increase in Annual Transmission Revenue Requirements . . . to be paid by Delaware and Maryland ratepayers." It and representatives of consumers on the Peninsula, including the A&N Electric Cooperative ("A&N") and the Choptank Electric Cooperative ("Choptank") which both serve Maryland residents, have complained that no showing of benefits to Peninsula residents has been made which could justify such a significant increase in cost burden for these customers, under Federal Energy Regulatory Commission ("FERC") precedent and the just and reasonable standard of the Federal Power Act. [1]

[1] *See, e.g.*, 16 U.S.C. § 824d(a); Re Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 at ¶ 612 et seq. (2011)(requiring costs to be allocated "in a way that is roughly commensurate with benefits"); *Illinois Commerce Commission v. FERC*, 721 F.3d 764 (7th Cir.

The Maryland Public Service Commission ("Maryland PSC") takes no position on which of the several project alternatives being considered should be selected to resolve these violations. However, it agrees that pursuit of this proposed Project with the cost allocation proposed by PJM Staff will not produce just and reasonable wholesale transmission rates for Delmarva residents.

The operational performance and planning criteria violations to be corrected by the selected Artificial Island transmission enhancement project, as stated in the original problem statement, are primarily related to improving the effective and stable operation of the 3800 MW of nuclear generation situated on Artificial Island. The Maryland PSC considers this to be a PJM system-wide or regional benefit, not a benefit focused primarily or solely on the limited load existing on the Delmarva Peninsula. Yet, the cost of the selected 230 kV solution is, under PJM tariff provisions, to be imposed almost entirely upon Delmarva Peninsula customers. See Delaware PSC Letter of May 29, 2015 at p. 4; A&N/Choptank Letter of May 29, 2015 at pp. 3-4. We do not view such a cost allocation as reasonably comparable to the benefits received from the project which we believe would flow equally to at least New Jersey and Pennsylvania residents. Thus, such an allocation of costs, we believe, is in violation of FERC's Order 1000 cost allocation principles and directives.

Therefore, the Maryland PSC urges the PJM Board and Staff to carefully consider its project selection and related cost allocation principles in light of the data and reasoning presented above and in the letters submitted by the Delaware PSC, A&N and Choptank. Further, PJM Staff should fully justify that the allocation of costs of the alternative chosen is reasonably comparable to the benefits received by the ratepayers burdened with those costs or should materially alter the cost allocation proposed.

Sincerely,

s/ W.K. Hughes

W. Kevin Hughes
Chairman

CC: David Anders, Director PJM Stakeholder Affairs
Paul McGlynn, Chair, Transm. Exp. Adv. Committee
Denise Foster, Vice President, State and Member Services

2013)("The requirement of proportionality between costs and benefits requires that all beneficiaries . . . shoulder a reasonable portion of MVP costs.").

State of Delaware
OFFICE OF THE GOVERNOR
Tatnall Building, Second Floor
William Penn Street, Dover, DE 19901

Jack A. Markell
Governor

Phone: 302-744-4101
Fax: 302-739-2775

July 13, 2015

Mr. Howard Schneider
Chair, PJM Board of Managers
PJM Interconnection
PO Box 1525
Southeastern, PA 19399-1525

RE: Artificial Island Facilities Project

Dear Mr. Schneider:

On behalf of the State of Delaware, I urge you and your colleagues on the PJM Board of Managers to reconsider proceeding with the Artificial Island facilities project as proposed without adopting a more equitable and reasonable cost allocation. As the project is currently structured, Delaware consumers would bear over $100 million of costs associated with the project in exchange for a very small portion of the value it would create. This failure to allocate costs in accordance with benefits is inequitable and unreasonable.

As you know, the Artificial Island facilities project was developed to solve a problem – how to generate maximum power from the Artificial Island units while reducing operational complexity and maintaining stability of the generation from those units. PJM's Transmission Expansion Advisory Committee (TEAC) did significant work to evaluate solutions to that problem. TEAC's analysis concludes that the proposed solution – a 230 kV power line from Artificial Island to Red Lion in Delaware – is technically superior and I do not take a position on the specific solution selected.

However, TEAC's analysis also concludes that the Artificial Island solution would result in almost all of the significant project costs being allocated to residential, commercial and industrial consumers in the Delmarva Peninsula, including customers of Delmarva Power & Light Company, Delaware Municipal Electric Corporation, and the Delaware Electric Cooperative.

According to the Delaware Public Service Commission, this project could result in an approximate twenty-five percent increase in transmission costs in Delaware. For the average residential consumer, monthly electric bills could increase by several dollars. For the average business, the increase may be more significant. Some of our heaviest users could see increases of hundreds of thousands of dollars.

It seems patently unfair that electricity users in the Delmarva Peninsula would bear almost the entirety of the costs of a project for which the principal benefit is not expanded energy transmission in Delaware, but maximizing power from generating units in New Jersey that serve customers throughout the PJM region. Allocating to Delaware and Maryland consumers the bulk of those costs for a project not necessitated by demand in this area is neither reasonable nor equitable.

Given the evidence before me, I can only conclude that any attempt to solve the operational performance issues at the Artificial Island facilities, as currently planned, would not be in the best interests of Delaware consumers unless the project costs were assessed in a manner that better reflect the expected benefits. I urge the PJM Board to allow the Artificial Island facilities project to proceed only after PJM's adoption and FERC's approval of a cost allocation that appropriately shares these costs among all project beneficiaries.

I recognize that cost allocation issues are governed by FERC rules and tariffs submitted by transmission owners. But those same FERC rules require cost allocations to be reasonable and allocated in a manner commensurate with project benefits. I believe this is a time when PJM must show leadership by recognizing that imposing all the costs for the Artificial Island project on Delaware and Maryland consumers is neither reasonable nor fair.

Chairman Dallas Winslow of the Delaware Public Service Commission also sent you a letter suggesting that the Board delay decision on the project until a better cost allocation methodology is adopted. I echo the sentiments he conveyed in that letter and endorse his recommendations. I urge you to delay proceeding with the project unless costs can be shared reasonably and equitably among all those who benefit from increasing generation at Artificial Island, and not just local electricity users that happen to be on the receiving end of this project.

I trust that you will take the outlined reasoning into consideration.

Sincerely,

Jack Markell

Jack A. Markell

July 17, 2015

Howard Schneider, Esq.
Chair, Board of Managers
PJM Interconnection, L.L.C.
P.O. Box 1525
Southeastern, PA 19399-1525

RE: ***Artificial Island Facilities Project***

Dear Mr. Schneider:

The undersigned Delaware businesses[1] seek to share their serious concerns with PJM's plan to allocate almost all of the costs attributable to the proposed Artificial Island Facilities Project to customers located on the Delmarva Peninsula. As noted in Governor Markell's correspondence dated July 13, 2015, and the Delaware Public Service Commission's correspondence dated May 27, 2015, PJM Staff's proposed cost allocation will impose the bulk of the Project's costs on a small subset of PJM customers, namely those customers within the Delmarva zone and within Delaware in particular. Understanding the nature of the Artificial Island Project and the reliability problem it was designed to address, we urge the Board to scrutinize closely the appropriateness of PJM's DFAX analysis, determine if PJM's Solution-based DFAX was conducted correctly, and determine if the allocation of costs produced by that methodology is consistent with the "beneficiary pays" principle underpinning FERC Order No. 1000 and PJM's Tariff.

As has been well documented, the Artificial Island Facilities Project was developed by LS Power to address operational performance issues and eliminate potential planning criteria violations identified by PJM in New Jersey at the Salem and Hope Creek nuclear generating stations, which share Artificial Island. We value PJM's planning expertise and do not take a position on the underlying reliability problem, and we do not have enough information about the merits of the numerous projects proposed to remedy the Artificial Island deficiencies. However, we note that past generation interconnection studies concerning up-rates to generation output at the Artificial Island complex performed by, or on behalf of, PJM, including a recent 50 MW up-rate that went in service in 2013, failed to identify the reliability problem for which Delmarva customers are now being asked to shoulder cost responsibility.[2]

[1] Please note that Kuehne Chemical Company, Inc., Linde LLC, and PBF Power Marketing, an affiliate of Delaware City Refining Company LLC, are PJM Members.

[2] A review of the PJM Generation Interconnection Queues indicates that Artificial Island generator output was increased by 95 MW in 2001, by 236 MW in 2007-2008, and by 50 MW as recently as 2013, only a few months after PJM discussed the Artificial Island issue with stakeholders and a few months prior to issuing the Artificial Island RFP in April 2013. In approving the prior up-rates at Artificial Island, PJM appears to have permitted the use of minimum MVAR requirements and complex operating guides in lieu of requiring the generation owner to reinforce the transmission system to provide adequate stability margins as is now being requested through the Artificial Island Proposal Window RFP.

Struggles on transmission project cost allocation have a long history, and the question of transmission project cost allocation has been vigorously debated in the PJM stakeholder process and litigated at the Commission and in appellate courts. The Commission and the courts have consistently required cost allocation to follow cost-causation principles; the beneficiary-pays principle has become the metric by which cost causation is determined. Under the beneficiary-pays principle, cost allocations must be roughly commensurate with the benefits to entities that are paying the allocated costs. In Order No. 1000, the Commission, in an effort to reduce the uncertainty bred by cost allocation questions, mandated PJM utilize an *ex ante* cost allocation methodology to identify beneficiaries of proposed transmission facilities. For Regional and Lower Voltage projects, PJM is required to utilize a Solution-based DFAX methodology to determine the beneficiaries for all or part of the cost allocation. While the cost allocation methodology may now be explicit in the PJM Tariff, it has not in any way reduced the level of controversy on cost allocation questions in certain cases, including instances such as this when legitimate questions are being asked whether the Solutions-based DFAX methodology is producing just and reasonable results.

As businesses for which reliability is a paramount concern, we appreciate and understand that we will be called upon to pay for transmission projects necessary to support reliable operations, including projects like that proposed by LS Power. However, we should not reasonably be forced to pay all of the costs of a transmission project that may have other beneficiaries. Our interest is ensuring that the cost allocation meets the goals of cost-causation and beneficiary-pays principles, and that may require revisiting PJM's Solution-based DFAX analysis, if not revisiting the continued appropriateness of this methodology to determine cost allocation under such circumstances.

We understand that PJM's Solution-based DFAX analysis indicates that Delmarva customers will presumably receive virtually all of the benefits, which is why Delmarva customers are apparently receiving the associated bill for the project.[3] This stands in stark contrast to the original Artificial Island Proposal Window Problem Statement issued on April 29, 2013, which did not reference any problems existing on the Delmarva Peninsula. The problems to be solved all related to generator stability and operational issues at the Salem and Hope Creek nuclear plants in southern New Jersey. As Governor Markell's letter aptly pointed out, the Artificial Island Facilities Project was developed to "generate maximum power from the Artificial Island units while reducing operational complexity and maintaining stability of the generation from those units." Because the problem to be solved focused on necessary infrastructure to allow a generation facility additional outlets for its energy, we reasonably question how PJM's Solution-based DFAX analysis can suggest that Delmarva customers are receiving all of the benefits and, as such, all of the costs of the project to solve this generator stability and operational issue.

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[3] We believe this determination results from the creation of a new tie-line for a zone (in this case, Delmarva) and the application of the Solution-based DFAX methodology that simulates a transfer between the Delmarva zone and all generation in the PJM region. Accordingly, Solution-based DFAX analysis may not be appropriate for facilities on or close to zonal boundaries.

The mismatch between the original Problem Statement and the output of PJM's Solution-based DFAX has not been adequately explained and is at the heart of the concern we raise to your attention. When the objectives of the original Problem Statement focused entirely on generator stability and operational issues associated with the Salem and Hope Creek nuclear plants in New Jersey, it does not logically follow that virtually the only (*i.e.*, 90%) beneficiary of the resulting "solution" would be Delmarva customers, particularly when maximizing power from these generating units benefits customers in a much larger footprint than just the Delmarva Peninsula. In such circumstances, it behooves the PJM Board to question why other proximate load, if not the generator owner itself, is not being held responsible for even a portion of the costs of solving the Artificial Island problem.

We support the Commission's objectives in issuing Order No. 1000 and PJM's diligent efforts to implement the fundamental changes in transmission planning that Order No. 1000 represents. In our view, the Artificial Island experience reflects the growing pains that are inevitable with such transformation in the industry. The Board displayed leadership and courage in July 2014 to defer decision on the Artificial Island proposal selected. We respectfully submit that similar leadership and courage is necessary again now with respect to Artificial Island to ensure that the project selected by PJM Staff and the cost allocation produced by PJM's Solution-based DFAX do not undercut PJM's important efforts to implement Order No. 1000 in a just and reasonable manner.

At the very minimum, if the Board elects to move forward with the LS Power solution at its upcoming Board meeting, PJM should reclassify all components of the LS Power solution (*e.g.*, the 230 kV transmission line between Salem and Silver Run and the Salem 500/230 kV transformer at Salem), as either Regional Facilities or Necessary Lower Voltage Facilities as opposed to mere Lower Voltage Facilities. If broader action is not taken by the Board on the issues raised by us and many others, including the Governor of the State of Delaware, and the LS Power solution were to be approved, such classification is appropriate because these facilities must be constructed to support the broad-based solution selected to address the regional reliability problems identified in the RFP. Classifying these components of the LS Power solution in either such manner changes the cost allocation to Delmarva customers from $246.4 million to $141.0 million, a cost savings of $105.4 million. We believe that such approach better honors the beneficiary-pays principle and is consistent with PJM's tariff.

We appreciate the Board's consideration of our serious concerns.

Very truly yours,

/s/ Thomas F. Martinelli
Thomas F. Martinelli
Executive Buyer – Energy
E. I. du Pont de Nemours and Company

/s/ Bill Fasy
Bill Fasy
President
Delaware Racing Association

/s/ Alan M. Rogers
Alan M. Rogers
Plant Manager – Delaware Plant
Kuehne Chemical Company

/s/ José Dominguez
José Dominguez
Refinery Manager
Delaware City Refining Company LLC

/s/ Robert Mulrooney
Robert Mulrooney, PE
Vice President, Facilities and Services
Christiana Care Health System

/s/ Larry Stalica
Larry Stalica
Head of Energy, Americas
Linde LLC

c: David A. Anders, PE, PJM Interconnection, L.L.C.

ODEC Old Dominion Electric Cooperative

VIA ELECTRONIC DELIVERY

July 28, 2015

Mr. Howard Schneider
Chair
Board of Managers
PJM Interconnection, L.L.C.
P.O. Box 1525
Southeastern, PA 19399-1525

RE: Supplemental Comments of Old Dominion Electric Cooperative on PJM Staff Artificial Island Recommendation

Dear Mr. Schneider:

In its May 29, 2015 comments to the PJM Board of Managers, Old Dominion Electric Cooperative ("ODEC"), on behalf of itself and its member cooperatives serving customers on the Delmarva Peninsula, expressed concern that PJM Staff's Artificial Island recommendation ("Recommended Proposal") could have a disproportionate cost impact on customers located in the Delmarva Power & Light Company ("Delmarva") Transmission Zone, particularly given that the primary purpose of the Artificial Island solution is to resolve generator stability and operational issues associated with nuclear plants in southern New Jersey. In order to evaluate this issue further, ODEC suggested that PJM Staff should provide the projected cost allocations for the proposed Artificial Island solutions, as well as a detailed economic benefit analysis of the proposals. In response to the requests of ODEC and other parties, PJM Staff provided certain cost allocation information on July 7, 2015 and a market efficiency analysis on July 24, 2015. ODEC appreciates the time and effort that PJM Staff put into this analysis. Unfortunately, the timing of the issuance of the analysis has left very little time for Board consideration of this important information or supplemental comments on the same.

The information recently provided by PJM Staff has only heightened ODEC's concerns about the disproportionate cost impact on the Delmarva Zone.

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PJM Staff's cost allocation analysis indicates that the Delmarva Zone would be allocated $246.43 million of the projected $275.45 million cost (89.5 percent) of the Recommended Proposal. Even assuming a conservative 15 percent carrying charge for these costs, the annual charges to the Delmarva Zone would be nearly $37 million. PJM Staff's market efficiency analysis, however, shows that only about 10 percent ($17.04 million) of the total projected annual load payment savings of $169.2 million would accrue to the Delmarva Zone. (See attached PJM Staff analysis at page 5.) Moreover, the Staff analysis shows that the market efficiency benefits of the Recommended Proposal would be spread widely among the PJM transmission zones, which presumably would also be true of PSEG's Artificial Island proposal incorporating a 500 kV line from Hope Creek to Red Lion ("PSEG Proposal").

Based on the totality of the information provided to the Board, ODEC submits that the PSEG Proposal would reflect a more appropriate matching of costs and benefits than the Recommended Proposal, as 50 percent of the costs of the 500 kV facilities in the PSEG Proposal would be allocated to all PJM zones on a load ratio share basis and 50 percent of the costs would be allocated using solution-based DFAX. In these circumstances, where the Board has been presented with two sound technical solutions that are both designed to address the same operational performance issues and that both cost roughly the same, the Board should give significant weight to the proposal that would better match costs with project beneficiaries, which in this case appears to be the PSEG Proposal.

Sincerely,

Peter Gallini
Vice President of Power Supply
Old Dominion Electric Cooperative

Attachment

PJM Market Efficiency Study
Artificial Island Benefits

Requested by Delaware Public Service Commission

Study Assumptions

Market Efficiency Project Study approach:

- Utilized PJM Market Efficiency Base Case for study year 2019
- Compared LMP and Load Payments between the following scenarios for both a single hour* and annual value:
  - System without Artificial Island solution and one Salem Unit Offline**
  - System with Artificial Island solution and all Salem Units Online

* *Single hour derived from RTO* Coincident Peak using 2019 Base Simulation
***Annual assumes one Salem unit offline for entire simulated year.*

Results using RTO Coincident Peak Hour

- RTO Coincident Peak hour from simulation: July 31, 2019
- RTO Peak Load from simulation: 155,382 MWs

- Simulation results show that the Artificial Island project decreases LMP in Delmarva Zone (DPL) for the Peak hour by $3.5/MWh and Load Payments by $13,772/h.
  - Base case assumes no Artificial Island solution and one Salem Unit offline.

Annual LMP Benefits Due To Artificial Island Solution*

- During the peak months of July and August, the market simulation shows an average LMP decrease in DPL Zone of 2.20 $/MWh and 1.90 $/MWh, respectively.
- The annual LMP average across DPL decreases by 0.86 $/MWh.
- The PJM average LMP decreases by 0.52 $/MWh in July, and 0.30 $/MWh in August.

LMP Avg. Benefits Due to Artificial Island Solution (negative value is a benefit, a decrease in LMP)

Area	Month												
	1	2	3	4	5	6	7	8	9	10	11	12	Annual Average
AECO	$(0.15)	$(0.26)	$(0.82)	$(0.80)	$(0.18)	$(0.72)	$(1.79)	$(1.27)	$(1.01)	$(0.35)	$(0.48)	$(0.71)	$ (0.77)
AEP	$(0.23)	$(0.32)	$(0.01)	$(0.10)	$ 0.11	$(0.02)	$(0.11)	$(0.01)	$(0.10)	$ 0.25	$(0.19)	$ 0.01	$ (0.06)
APS	$(0.01)	$(0.19)	$(0.35)	$(0.11)	$ 0.38	$(0.07)	$(0.22)	$(0.11)	$(0.24)	$ 0.18	$(0.23)	$(0.06)	$ (0.09)
BGE	$ 0.04	$ 0.14	$(0.47)	$(0.20)	$ 0.20	$(0.12)	$(0.41)	$(0.17)	$(0.47)	$(0.06)	$(0.35)	$(0.28)	$ (0.18)
COMED	$(0.22)	$(0.29)	$ 0.44	$(0.36)	$(0.08)	$ 0.02	$(0.05)	$ 0.08	$ 0.01	$ 0.01	$ 0.48	$ 0.15	$ 0.02
DAY	$(0.31)	$(0.49)	$ 0.16	$(0.05)	$(0.00)	$(0.01)	$(0.09)	$ 0.00	$(0.06)	$ 0.44	$(0.15)	$(0.00)	$ (0.05)
DEOK	$(0.28)	$(0.47)	$ 0.20	$(0.14)	$(0.04)	$(0.02)	$(0.08)	$ 0.00	$(0.05)	$ 0.53	$(0.11)	$(0.01)	$ (0.04)
DOM	$ 0.02	$ 0.28	$(0.33)	$(0.04)	$ 0.31	$ 0.02	$(0.16)	$(0.03)	$(0.09)	$ 0.07	$(0.47)	$(0.16)	$ (0.05)
DPL	$(0.19)	$(0.22)	$(0.85)	$(0.70)	$(0.27)	$(0.77)	$(2.20)	$(1.90)	$(1.05)	$(0.36)	$(0.57)	$(0.77)	$ (0.86)
DUQ	$(0.16)	$(0.10)	$(0.69)	$(0.37)	$ 0.42	$(0.15)	$(0.23)	$(0.12)	$ 0.12	$ 0.70	$(1.04)	$(0.10)	$ (0.14)
EKPC	$(0.22)	$(0.38)	$ 0.11	$ 0.01	$ 0.03	$(0.01)	$(0.06)	$ 0.05	$(0.09)	$ 0.27	$(0.14)	$(0.01)	$ (0.05)
FE-ATSI	$(0.07)	$(0.20)	$(0.30)	$(0.38)	$ 0.22	$(0.15)	$(0.21)	$(0.08)	$(0.04)	$ 0.40	$(0.54)	$(0.07)	$ (0.12)
JCPL	$(0.12)	$(0.28)	$(0.71)	$(0.44)	$ 0.07	$(0.61)	$(1.52)	$(1.02)	$(0.85)	$(0.23)	$(0.41)	$(0.58)	$ (0.59)
METED	$ 0.00	$(0.12)	$(0.78)	$(0.62)	$(0.15)	$(0.62)	$(1.18)	$(0.69)	$(1.15)	$(0.24)	$(0.38)	$(0.46)	$ (0.54)
PECO	$(0.10)	$(0.24)	$(0.68)	$(0.61)	$(0.12)	$(0.63)	$(1.79)	$(1.23)	$(0.91)	$(0.22)	$(0.40)	$(0.63)	$ (0.66)
PENELEC	$ 0.12	$ 0.03	$(0.14)	$(0.51)	$ 0.05	$(0.41)	$(0.64)	$(0.44)	$(0.55)	$(0.16)	$(0.11)	$(0.19)	$ (0.24)
PEPCO	$ 0.03	$ 0.23	$(0.37)	$(0.03)	$ 0.36	$ 0.03	$(0.22)	$(0.05)	$(0.17)	$ 0.01	$(0.37)	$(0.20)	$ (0.06)
PLGRP	$(0.04)	$(0.15)	$(0.69)	$(0.45)	$(0.04)	$(0.56)	$(1.22)	$(0.80)	$(0.79)	$(0.15)	$(0.31)	$(0.50)	$ (0.48)
PSEG	$(0.16)	$(0.28)	$(0.70)	$(0.45)	$ 0.05	$(0.58)	$(1.49)	$(1.00)	$(0.81)	$(0.08)	$(0.59)	$(0.62)	$ (0.59)
RECO	$(0.35)	$(0.88)	$(1.95)	$(0.14)	$ 0.44	$(0.69)	$(0.93)	$(0.71)	$(0.65)	$ 0.09	$(0.81)	$(0.41)	$ (0.59)
PJM	$(0.11)	$(0.15)	$(0.25)	$(0.27)	$ 0.10	$(0.19)	$(0.52)	$(0.30)	$(0.31)	$ 0.09	$(0.25)	$(0.18)	$ (0.20)

**Simulation assumes one Salem unit offline for entire year.*

Annual Load Payment Savings Due To Artificial Island Solution*

- During the peak months of July and August, the market simulation shows a decrease of the monthly load payments across DPL zone of $4.32 million and $3.64 million, respectively.
- The annual total load payments across DPL zone decreases by $17.04 million.
- The PJM annual total load payments decrease by $169.2 million.

Load Payments Savings Due to Artificial Island Solution ($ million, negative value is a benefit, a decrease in load payments)

Area	Month												
	1	2	3	4	5	6	7	8	9	10	11	12	Annual Total
AECO	$ (0.14)	$ (0.22)	$ (0.67)	$ (0.60)	$ (0.15)	$ (0.73)	$ (2.13)	$ (1.46)	$ (0.91)	$ (0.28)	$ (0.38)	$ (0.64)	$ (8.28)
AEP	$ (2.82)	$ (3.54)	$ (0.13)	$ (0.99)	$ 1.16	$ (0.21)	$ (1.34)	$ (0.17)	$ (1.05)	$ 2.57	$ (1.98)	$ 0.06	$ (8.43)
APS	$ (0.04)	$ (0.84)	$ (1.49)	$ (0.43)	$ 1.48	$ (0.29)	$ (0.97)	$ (0.51)	$ (0.93)	$ 0.73	$ (0.91)	$ (0.28)	$ (4.46)
BGE	$ 0.14	$ 0.39	$ (1.31)	$ (0.50)	$ 0.52	$ (0.35)	$ (1.37)	$ (0.55)	$ (1.29)	$ (0.14)	$ (0.91)	$ (0.83)	$ (5.22)
COMED	$ (2.09)	$ (2.47)	$ 3.78	$ (2.89)	$ (0.71)	$ 0.14	$ (0.49)	$ 0.82	$ 0.08	$ 0.08	$ 4.04	$ 1.41	$ 1.70
DAY	$ (0.52)	$ (0.73)	$ 0.24	$ (0.07)	$ (0.00)	$ (0.02)	$ (0.15)	$ 0.00	$ (0.09)	$ 0.64	$ (0.21)	$ (0.00)	$ (0.92)
DEOK	$ (0.70)	$ (1.04)	$ 0.45	$ (0.28)	$ (0.09)	$ (0.04)	$ (0.22)	$ 0.00	$ (0.10)	$ 1.14	$ (0.24)	$ (0.02)	$ (1.16)
DOM	$ 0.17	$ 2.46	$ (2.86)	$ (0.32)	$ 2.53	$ 0.19	$ (1.58)	$ (0.26)	$ (0.80)	$ 0.57	$ (3.95)	$ (1.49)	$ (5.33)
DPL	$ (0.34)	$ (0.35)	$ (1.35)	$ (0.99)	$ (0.40)	$ (1.33)	$ (4.32)	$ (3.64)	$ (1.66)	$ (0.53)	$ (0.85)	$ (1.32)	$ (17.04)
DUQ	$ (0.22)	$ (0.13)	$ (0.88)	$ (0.43)	$ 0.51	$ (0.21)	$ (0.35)	$ (0.17)	$ 0.15	$ 0.36	$ (1.27)	$ (0.14)	$ (2.26)
EKPC	$ (0.26)	$ (0.39)	$ 0.10	$ 0.01	$ 0.03	$ (0.01)	$ (0.06)	$ 0.65	$ (0.68)	$ 0.23	$ (0.13)	$ (0.01)	$ (0.53)
FE-ATSI	$ (0.44)	$ (1.13)	$ (1.76)	$ (2.03)	$ 1.22	$ (0.89)	$ (1.36)	$ (0.50)	$ (0.23)	$ 2.19	$ (2.96)	$ (0.40)	$ (8.28)
JCPL	$ (0.25)	$ (0.53)	$ (1.37)	$ (0.77)	$ 0.13	$ (1.34)	$ (3.90)	$ (2.52)	$ (1.71)	$ (0.42)	$ (0.75)	$ (1.19)	$ (14.62)
METED	$ 0.00	$ (0.16)	$ (1.08)	$ (0.78)	$ (0.19)	$ (0.88)	$ (1.80)	$ (1.04)	$ (1.53)	$ (0.31)	$ (0.50)	$ (0.68)	$ (8.96)
PECO	$ (0.39)	$ (0.81)	$ (2.38)	$ (1.93)	$ (0.39)	$ (2.35)	$ (7.56)	$ (5.05)	$ (3.20)	$ (0.72)	$ (1.33)	$ (2.32)	$ (28.46)
PENELEC	$ 0.22	$ 0.04	$ (0.24)	$ (0.79)	$ 0.08	$ (0.65)	$ (1.09)	$ (0.76)	$ (0.88)	$ (0.26)	$ (0.18)	$ (0.34)	$ (4.87)
PEPCO	$ 0.08	$ 0.59	$ (0.95)	$ (0.07)	$ 0.91	$ 0.07	$ (0.73)	$ (0.15)	$ (0.45)	$ 0.04	$ (0.89)	$ (0.55)	$ (2.10)
PLGRP	$ (0.15)	$ (0.55)	$ (2.58)	$ (1.49)	$ (0.12)	$ (2.00)	$ (4.72)	$ (3.09)	$ (2.70)	$ (0.50)	$ (1.08)	$ (2.00)	$ (20.97)
PSEG	$ (0.61)	$ (0.96)	$ (2.54)	$ (1.50)	$ 0.20	$ (2.40)	$ (6.99)	$ (4.55)	$ (3.11)	$ (0.29)	$ (2.02)	$ (2.33)	$ (27.10)
RECO	$ (0.04)	$ (0.10)	$ (0.23)	$ (0.02)	$ 0.05	$ (0.10)	$ (0.15)	$ (0.11)	$ (0.09)	$ 0.01	$ (0.05)	$ (0.05)	$ (0.92)
PJM	$ (8.40)	$ (10.46)	$ (17.24)	$ (16.88)	$ 6.77	$ (13.35)	$ (41.29)	$ (23.66)	$ (20.57)	$ 5.61	$ (16.58)	$ (13.13)	$ (169.20)

*Simulation assumes one Salem unit offline for entire year.

Distribution Factor Allocations

DFAX ALLOCATIONS WITH AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.7%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.5%	0.0%	0.0%	47.0%	1.9%
Salem - Hope Creek	22.8%	1.1%	0.0%	0.0%	41.4%	4.4%	0.0%	0.0%	0.0%	0.0%	29.1%	1.2%
Salem - Orchard	8.2%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.6%	0.0%	0.0%	46.5%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	17.1%	2.0%	1.5%	20.6%	0.0%	0.0%	54.9%	2.2%
Hope Creek - New Freedom	7.7%	0.0%	0.0%	1.3%	16.8%	1.8%	1.2%	22.4%	0.0%	0.0%	47.0%	1.9%
Hope Creek - Red Lion	1.9%	36.0%	29.4%	1.2%	3.2%	0.3%	1.7%	0.0%	0.0%	26.3%	0.0%	0.0%

DFAX ALLOCATIONS WITHOUT AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.6%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	22.9%	0.0%	0.0%	46.8%	1.9%
Salem - Hope Creek	21.2%	3.8%	7.7%	0.0%	41.2%	4.4%	0.0%	0.0%	0.0%	0.0%	20.9%	0.9%
Salem - Orchard	8.1%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	23.1%	0.0%	0.0%	46.2%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	16.9%	2.0%	1.5%	21.0%	0.0%	0.0%	54.7%	2.2%
Hope Creek - New Freedom	7.6%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.8%	0.0%	0.0%	46.7%	1.9%
Hope Creek - Red Lion	0.6%	26.1%	51.6%	0.9%	1.1%	0.1%	1.3%	0.0%	0.1%	18.3%	0.0%	0.0%

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August 6, 2015

VIA ELECTRONIC MAIL

PJM Transmission Owners
Mr. Frank J. Richardson, II (FJRichardson@pplweb.com)
Chairman, Transmission Owners Administrative Committee

Re: **THE DELAWARE DIVISION OF THE PUBLIC ADVOCATE'S REQUEST TO PJM TRANSMISSION OWNERS REGARDING THE PJM BOARD OF MANAGERS SELECTION OF THE LS POWER 5A ARTIFICIAL ISLAND PROJECT FOR RESOLUTION OF SYSTEM OPERATING AND RELIABILITY CONCERNS**

Dear Mr. Richardson:

At its July 29, 2015 the PJM Board of Managers selected LS Power's proposed project (the "Project") to remedy operational performance issues and eliminate potential planning criteria violations (e.g., NERC, RFC, etc.) at Artificial Island ("AI"). The Project involves, among other things, constructing a new 230kV circuit from Salem to a new substation near the 230kV corridor in Delaware (using horizontal directional drilling under the Delaware River), tapping the existing Red Lion to Cartanza and Red Lion to Cedar Creek 230 kV lines.

Under PJM's cost allocation procedures, the Delmarva Power & Light ("DP&L") transmission zone will be responsible for 99.99% of the costs of the 230 kV portion of the Project, and the Jersey Central Power & Light ("JCPL") will be responsible for only 0.01% of the costs of the 230 kV portion of the Project. Half of the allocation for the 500 kV portions will be socialized to New Jersey and the other half of the project will be allocated to DP&L and JCPL based on the 99.99%/0.01% split. The Delaware Division of the Public Advocate ("DPA") joins the Delaware Public Service Commission in respectfully requesting the PJM Transmission Owners ("TOs") to review the cost allocation related to the Project and to consider possible alternatives that may be more appropriate in this and other similar circumstances.

The DPA respectfully submits that allocating virtually the entire amount of the 230kV cost to the Delmarva transmission zone is neither logical nor fair. The Project's purpose is to alleviate an operational problem in the New Jersey transmission zone, and the vast majority of

Project stability benefits will accrue to the New Jersey transmission zone.[1] It is incontrovertible that the enhanced stability of Artificial Island will benefit New Jersey end users as well as residents of Delaware, Maryland and Virginia. If PJM's cost allocation procedures are intended to recognize the beneficiaries of transmission facilities, *this* cost allocation – which ignores the fact that the New Jersey transmission zone is the predominant beneficiary of the Project - violates that intent. Further, the impact on Delaware ratepayers of the allocation of virtually 100% of Project costs to the Delmarva transmission zone is significant:[2] The Delaware Public Service Commission staff has calculated that the Annual Transmission Revenue Requirement for the Delmarva transmission zone could increase by nearly 25%.[3]

The DPA respectfully requests the PJM TOs to consider the unique situation in which AI's reliability problems exist. We believe that PJM's procedures provide for such consideration. *See, e.g.,* PJM Manual 14B: PJM Regional Transmission Planning Process, §2.6.4 ("Evaluation of cost/benefit of advancing reliability projects"); §A.3 Schedule 12. Furthermore, Manual 14B Section 1.3 Schedule 12 specifically states that "*[a]llocation of transmission upgrades for reliability is beneficiary based.*" (Emphasis added). Finally, Manual 14B §2.5 provides that "[t]he cost responsibility for each baseline-revealed Network Reinforcement is borne by transmission owners *based on the contribution to the need for the network reinforcement.*" (Emphasis added).

While the AI Area Network includes some Delmarva transmission facilities, it is clear that those facilities are not the sole reason for the network reinforcement contemplated in the Project. Indeed, PJM Staff has yet to identify to what extent (if any) the Delmarva transmission facilities included in the AI Area Network contributed to the need for the Project. What *is* clear, however, is that the Project is intended to remedy issues in the *New Jersey transmission zone*. *See supra* n.1.

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[1] PJM has identified the following Project benefits: (1) Generate maximum power (3818 MW total) from all AI Units (Salem-1: 1253MW; Salem-2: 1245MW; Hope Creek: 1320MW) without a minimum MVAr requirement from AI. Maintaining full maximum power under both the baseline and all N-1 outage conditions of 500kV transmission lines in the AI area. Maintaining AI voltage within operating limits and stable for all NERC Category B and C contingencies. (2) Maximum MW output from AI should not be affected by the simultaneous outage of Power System Stabilizers (PSS) of AI units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios. (3) Reduce operational complexity. (4) Improve AI stability. (5) Maintain PJM System Operating Limits (SOLs). *See* http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/redacted-artificial-island-problem-statement.ashx

[2] Old Dominion Electric Cooperative and Delaware Municipal Electric Corporation ratepayers will also be affected by this cost allocation.

[3] Based on Delmarva Power & Light Company's most recent last Annual Update, the Network Service Revenue Requirement for transmission service(s) effective June 1, 2014 was approximately $121 million. If the in-service costs for the Project and other AI facilities are $200 million with a conservative 15% carrying charge, the impact on the current Network Service Revenue Requirement for Delmarva transmission service(s) would be $30 million, which is an approximate 25% increase.

The DPA is not suggesting that the Delmarva transmission zone should not be allocated any of the Project costs: to the contrary, the DPA acknowledges that the Project does provide some system benefits and additional transmission support on the Delaware peninsula. The DPA respectfully submits, however, that there is no logical or fair basis for allocating almost 100% of the costs of the Project to the Delmarva transmission zone. The DPA joins the Delaware Public Service Commission in encouraging the TOs to address this and similar cost allocation issues where the use of the Solution Based DFAX allocates costs in an unfair and inequitable manner. As the Delaware Commission observed, "a cost allocation process that forces high energy use industries in one transmission zone to absorb the network costs for benefits to competing industries in neighboring zones creates a discriminatory business environment that foretells economic relocations and the related state impacts for industries that rely on lower energy costs to remain competitive."

The DPA looks forward to discussing these issues with you next Monday.

Very truly yours,

David L. Bonar
Public Advocate for the State of Delaware

DLB/rai

cc: The Honorable Jack Markell, Governor of the State of Delaware
Mr. Howard Schneider, Chair, PJM Board of Managers
Mr. Michael Kormos, Executive Vice President, PJM
Mr. Craig Glazer, Vice President-Federal Government Policy, PJM
Mr. Steven Herling, PJM Vice President – Planning
Mr. Paul McGlynn, Chair, Transmission Expansion Advisory Committee
Mr. David Anders, Director, PJM Stakeholder Affairs
Mr. Gregory Carmean, Executive Director, OPSI
Mr. Daniel Griffith, Executive Director, CAPS
Commissioners, Delaware Public Service Commission
Mr. Robert Howatt, Executive Director, Delaware Public Service Commission
Mr. Matthew Hartigan, Deputy Director, Delaware Public Service Commission
Mr. John Farber, Public Utilities Analyst, Delaware Public Service Commission
Mr. Joseph Delosa, Public Utilities Analyst, Delaware Public Service Commission

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August 7, 2015

VIA ELECTRONIC DELIVERY

PJM Transmission Owners
Mr. Frank J. Richardson, II (FJRichardson@pplweb.com)
Chairman, Transmission Owners Administrative Committee

Re: **REQUEST OF DELAWARE PUBLIC SERVICE COMMISSION REGARDING THE PJM BOARD OF MANAGERS SELECTION OF THE LS POWER 5A ARTIFICIAL ISLAND PROJECT FOR RESOLUTION OF SYSTEM OPERATING AND RELIABILITY CONCERNS IN NEW JERSEY.**

At its July 29, 2015 meeting, the PJM Board of Managers selected the L.S. Power 5A project as the solution to operating and reliability concerns related to the Artificial Island complex. The Delaware Public Service Commission ("Delaware PSC") appreciates PJM's efforts to resolve these issues but has significant concerns with what appears to be the resulting cost allocation. Given the selection of this project, the Delaware PSC respectfully requests the Transmission Owners ("TOs") to review the cost allocation related to this project and to consider possible alternatives that may be more appropriate in this and other similar circumstances.

As the Transmission Owners within the PJM region, the cost allocation for this project is within the TOs' responsibility as approved by the Federal Energy Regulatory Commission ("FERC") and provided for in the PJM Tariff.[1] It is the Delaware PSC's understanding that the cost of the selected 230KV line, as a low voltage facility, will be based on PJM's Solution Based DFAX which will allocate 99.9 % of the 230KV line cost to the DPL Transmission Zone or approximately 89% of the total project cost, which includes certain 500KV high voltage improvements that are also required. The Delaware PSC considers this cost allocation patently unfair, substantially unrelated to the system benefits provided and neither reasonable nor equitable for the DPL Transmission Zone ratepayers. Unfortunately, that leaves the Delaware PSC with the only alternative of a 206 Complaint Filing at FERC and any further legal recourse that may be required. To avoid a long protracted proceeding related to the proposed cost allocation and to develop a just and reasonable cost allocation, the Delaware PSC urges the TOs to review potential cost allocation alternatives for

[1] PJM Tariff, Schedule 12 § (a)(i)

this and the few other similarly situated circumstances where such allocation creates an unfair burden on transmission ratepayers and is inconsistent with benefits.

Recognizing the need to correct transmission system deficiencies for the benefit of all, the Delaware PSC takes no position at this time regarding the need for the selected project or the selection criteria that PJM presented in the Transmission Expansion Advisory Committee meetings. The Delaware PSC is in no way suggesting that cost allocation should be a determining consideration in the selection of an appropriate project to solve technical system or market efficiency issues. What is being contested is the manner in which the FERC-approved cost allocation is being applied in this circumstance and the inequities that inevitably follow.

As previously noted in the Delaware PSC's letter to PJM and as expressed by other similar letters, there are ways to resolve this cost allocation issue and to avoid unnecessary and protracted proceedings. In the case of the Delaware PSC letter, the Commission urged consideration of three (3) specific factors **that when taken together**, [emphasis added] could support an alternative cost allocation. Upon further reflection, the Delaware PSC suggests the consideration of two additional factors that must also be satisfied to justify a different low voltage cost allocation process.

1. The cost allocation resulting from the Solution Based DFAX would significantly increase transmission rates paid by customers for transmission service;
2. The Solution Based DFAX assigns all (or nearly all) of the costs to a transmission zone which is different than the zone creating the system issue; and
3. The project solution requires new rights-of-way and new transmission equipment.

Additionally:

4. The operating and reliability concerns requiring transmission upgrades were caused by generator deliverability export or transmission limitation issues in one zone with over 50% of costs allocated to a nearby zone; and
5. The cost allocation is greater than or equal to twice (or some other agreed-upon value) the PJM-stated load benefits accruing to a specific transmission zone.

It is important to note that the circumstances under which a variation of the DFAX cost allocation may be appropriate are a key component of the requested review. The Delaware PSC believes the recognition of these five unique, specific and objectively determined circumstances could provide justification for a different cost allocation that more accurately reflects the benefits in relation to the cost. It should be recognized that, ultimately, the FERC[2] and the courts[3] that have addressed this issue have concluded that there must be a reasonable alignment[4] of cost allocation and beneficiaries.

[2] Order No. 1000, 136 FERC ¶ 61,051, FERC Stats. & Regs. ¶ 31,323 (July 21, 2011) at P 622 (Costs of new transmission facilities must be "allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.")

[3] *KN Energy, Inc. v. FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[A]ll approved rates reflect to some degree the costs actually caused by the customer who must pay them.")

[4] *KN Energy, Inc. v. FERC,* 968 F.2d at 1300-01 (quoting *Alabama Electric Cooperative, Inc v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982): "Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer." (internal footnotes omitted) (emphasis removed))

The final question for the TOs' consideration is how the cost allocation could be developed under these specific circumstances. The Delaware PSC encourages the TOs to examine alternative cost allocation options. The following suggestions can each provide a more just and reasonable cost allocation more closely aligned with benefits.

- With respect to high voltage facilities, transmission ratepayers live in the 50/50 world as filed by the TOs (50% shared on a PJM load ratio basis and 50% on a Solution Based DFAX) that has been approved by the FERC. Under the above mentioned circumstances and as advocated by several Delaware industries in their July 17 letter to the PJM Board, at a minimum, PJM should consider the underlying low voltage line as a regional system requirement or necessary lower voltage facility as permitted by PJM Manual 14B: PJM Region Transmission Planning Process, and allocate the costs of the entire solution on the 50/50 basis

- A second alternative would be to consider a cost allocation based on the economic load benefit to be derived from the selected solution. If this method were employed for this L.S. Power project, and based on PJM's Market Efficiency Study (Exhibit 1) (with which one may or may not agree), under the circumstances assumed in the analysis, the DPL Zone allocation would be approximately 10.1% of the project costs with up to 16.0% allocated to PSEG's New Jersey customers. [5]

- Another option for consideration could be a different combination of alternatives such as perhaps a 40/60 cost allocation under the above limited circumstances (40% shared on a PJM load ratio basis and 60% on a Solution Based DFAX analysis). The 40/60 allocation is a compromise based on the assumption that under the above circumstances, the project, although low voltage, does provide a broader system benefit for which at least some portion of the project should be paid.

Another factor that needs to be considered in this particular cost allocation review is the uprating of the Artificial Island nuclear units that has occurred over the past 15 years. The Delaware industries point out that "past generation interconnection studies concerning up-rates to generation output at the Artificial Island complex performed by, or on behalf of, PJM, including a recent 50 MW up-rate that went in service in 2013, failed to identify the reliability problem for which Delmarva customers are now being asked to shoulder cost responsibility."[6] An equitable cost allocation to relieve generation operational constraints, even if for only the peak 100 hours in the

[5] Other major beneficiaries are: PECO, at 16.8%; and PLGRP, at 12.4% (Exhibit 1). None of the aforementioned zones, each with PJM-calculated annual load payment savings greater than DPL, are currently allocated any cost for the 230KV section of the AI transmission upgrade.

[6] Delaware industries' July 17 Letter to the PJM Board. Their accompanying footnote reads: "A review of the PJM Generation Interconnection Queues indicates that Artificial Island generator output was increased by 95 MW in 2001, by 236 MW in 2007-2008, and by 50 MW as recently as 2013, only a few months after PJM discussed the Artificial Island issue with stakeholders and a few months prior to issuing the Artificial Island RFP in April 2013. In approving the prior up-rates at Artificial Island, PJM appears to have permitted the use of minimum MVAR requirements and complex operating guides **in lieu of requiring the generation owner to reinforce the transmission system to provide adequate stability margins as is now being requested through the Artificial Island Proposal Window RFP**." (Emphasis added)

year, should certainly carry costs in relation to the benefits to be received by the generator. The ability to run at full output during the 100 highest cost hours on the system without "operational difficulties" creates a windfall profit for the generator. It requires Delaware ratepayers to not only pay for the transmission that permits higher system generation levels, but also the windfall profits paid to generators who rely on that transmission for full operation.

The Delaware PSC encourages the TOs to address this and similar cost allocation issues where the use of the Solution Based DFAX allocates costs in an unfair and inequitable manner. A cost allocation process that forces high energy use industries in one transmission zone to absorb the network costs for benefits to competing industries in neighboring zones creates a discriminatory business environment that foretells economic relocations and the related state impacts for industries that rely on lower energy costs to remain competitive.

This is an important issue for the Delaware PSC and needs a cooperative approach for resolution. The Delaware Public Service Commission and others would be happy to meet with the TOs to further discuss potential resolutions to this issue. We hope the PJM Transmission Owners can consider a review process and amendment to the current cost allocation process that helps resolve these types of circumstances.

Sincerely,

Dallas Winslow, Chairman
Delaware Public Service Commission

Electronic Copies:
The Honorable Jack Markell, Governor
Commissioners, Delaware Public Service Commission
Mr. David Bonar, Delaware Public Advocate
Ms. Ruth A. Price, Delaware DeputyPublic Advocate
Mr. Robert Howatt, Executive Director, Delaware Public Service Commission
Mr. Matthew Hartigan, Deputy Director, Delaware Public Service Commission
Mr. John Farber, Public Utilities Analyst
Mr. Joe Delosa, Public Utilities Analyst
Mr. Howard Schneider, Chair, PJM Board of Managers
Mr. Craig Glazer, Vice President-Federal Government Policy, PJM
Mr. Michael Kormos, Executive Vice President, PJM
Mr. Steve Herling, PJM Vice President – Planning
Mr. Paul McGlynn, Chair, Transmission Expansion Advisory Committee
Mr. Gregory Carmean, Executive Director, OPSI

ATTACHED EXHIBIT 1

PJM Market Efficiency Study – Artificial Island Benefits
Requested by Delaware Public Service Commission

PJM Market Efficiency Study
Artificial Island Benefits

Requested by Delaware Public Service Commission

Study Assumptions

Market Efficiency Project Study approach:

- Utilized PJM Market Efficiency Base Case for study year 2019

- Compared LMP and Load Payments between the following scenarios for both a single hour* and annual value:
  - System without Artificial Island solution and one Salem Unit Offline**
  - System with Artificial Island solution and all Salem Units Online

* *Single hour derived from RTO* Coincident Peak using 2019 Base Simulation
***Annual assumes one Salem unit offline for entire simulated year.*

Peak Hour Benefits Due To Artificial Island Solution*

LMP Avg. Benefits Due to Artificial Island Solution (negative value is a benefit, a decrease in LMP)	
AECO	(3.4)
AEP	0.3
APS	0.9
BGE	(0.3)
COMED	0.4
DAY	0.3
DEOK	0.3
DOM	1.2
DPL	(3.5)
DUQ	(0.2)
LKPC	0.4
FE-ATSI	(0.1)
JCPL	(3.1)
METED	(4.9)
PECO	(3.2)
PENELEC	(1.3)
PEPCO	1.2
PLGRP	(3.2)
PSEG	(3.0)
RECO	(2.6)

Load Payments Benefits Due to Artificial Island Solution (Negative value is a benefit, a decrease in Load Payments)	
AECO	(8,200)
AEP	5,880
APS	7,557
BGE	(1,972)
COMED	8,530
DAY	770
DEOK	1,501
DOM	23,316
DPL	(13,772)
DUQ	(602)
EKPC	618
FE-ATSI	(1,770)
JCPL	(18,257)
METED	(14,097)
PECO	(25,998)
PENELEC	(4,050)
PEPCO	7,396
PLGRP	(23,500)
PSEG	(28,942)
RECO	(1,016)

*Simulated RTO coincident peak from 2019 simulation was 155,382 MWs on July 31.

Annual LMP Benefits Due To Artificial Island Solution

- During the peak months of July and August, the market simulation shows an average LMP decrease in DPL Zone of 2.20 $/MWh and 1.90 $/MWh, respectively.
- The annual LMP average across DPL decreases by 0.86 $/MWh.
- The PJM average LMP decreases by 0.52 $/MWh in July, and 0.30 $/MWh in August.

LMP Avg. Benefits Due to Artificial Island Solution (negative value is a benefit, a decrease in LMP)

Area	Month												
	1	2	3	4	5	6	7	8	9	10	11	12	Annual Average
AECO	\$(0.15)	\$(0.26)	\$(0.82)	\$(0.80)	\$(0.18)	\$(0.72)	\$(1.79)	\$(1.27)	\$(1.01)	\$(0.35)	\$(0.48)	\$(0.71)	\$ (0.77)
AEP	\$(0.23)	\$(0.32)	\$(0.01)	\$(0.10)	\$ 0.11	\$(0.02)	\$(0.11)	\$(0.01)	\$(0.10)	\$ 0.25	\$(0.19)	\$ 0.01	\$ (0.06)
APS	\$(0.01)	\$(0.19)	\$(0.35)	\$(0.11)	\$ 0.38	\$(0.07)	\$(0.22)	\$(0.11)	\$(0.24)	\$ 0.18	\$(0.23)	\$(0.06)	\$ (0.09)
BGE	\$ 0.04	\$ 0.14	\$(0.47)	\$(0.20)	\$ 0.20	\$(0.12)	\$(0.41)	\$(0.17)	\$(0.47)	\$(0.06)	\$(0.35)	\$(0.28)	\$ (0.18)
COMED	\$(0.22)	\$(0.29)	\$ 0.44	\$(0.36)	\$(0.08)	\$ 0.02	\$(0.05)	\$ 0.08	\$ 0.01	\$ 0.01	\$ 0.48	\$ 0.15	\$ 0.02
DAY	\$(0.31)	\$(0.49)	\$ 0.16	\$(0.05)	\$(0.00)	\$(0.01)	\$(0.09)	\$ 0.00	\$(0.06)	\$ 0.44	\$(0.15)	\$(0.00)	\$ (0.05)
DEOK	\$(0.28)	\$(0.47)	\$ 0.20	\$(0.14)	\$(0.04)	\$(0.02)	\$(0.08)	\$ 0.00	\$(0.05)	\$ 0.53	\$(0.11)	\$(0.01)	\$ (0.04)
DOM	\$ 0.02	\$ 0.28	\$(0.33)	\$(0.04)	\$ 0.31	\$ 0.02	\$(0.16)	\$(0.03)	\$(0.09)	\$ 0.07	\$(0.47)	\$(0.16)	\$ (0.05)
DPL	\$(0.19)	\$(0.22)	\$(0.85)	\$(0.70)	\$(0.27)	\$(0.77)	\$(2.20)	\$(1.90)	\$(1.05)	\$(0.36)	\$(0.57)	\$(0.77)	\$ (0.86)
DUQ	\$(0.16)	\$(0.10)	\$(0.69)	\$(0.37)	\$ 0.42	\$(0.15)	\$(0.23)	\$(0.12)	\$ 0.12	\$ 0.70	\$(1.04)	\$(0.10)	\$ (0.14)
EKPC	\$(0.22)	\$(0.38)	\$ 0.11	\$ 0.01	\$ 0.03	\$(0.01)	\$(0.06)	\$ 0.05	\$(0.09)	\$ 0.27	\$(0.14)	\$(0.01)	\$ (0.05)
FE-ATSI	\$(0.07)	\$(0.20)	\$(0.30)	\$(0.38)	\$ 0.22	\$(0.15)	\$(0.21)	\$(0.08)	\$(0.04)	\$ 0.40	\$(0.54)	\$(0.07)	\$ (0.12)
JCPL	\$(0.12)	\$(0.28)	\$(0.71)	\$(0.44)	\$ 0.07	\$(0.61)	\$(1.52)	\$(1.02)	\$(0.85)	\$(0.23)	\$(0.41)	\$(0.58)	\$ (0.59)
METED	\$ 0.00	\$(0.12)	\$(0.78)	\$(0.62)	\$(0.15)	\$(0.62)	\$(1.18)	\$(0.69)	\$(1.15)	\$(0.24)	\$(0.38)	\$(0.46)	\$ (0.54)
PECO	\$(0.10)	\$(0.24)	\$(0.68)	\$(0.61)	\$(0.12)	\$(0.63)	\$(1.79)	\$(1.23)	\$(0.91)	\$(0.22)	\$(0.40)	\$(0.63)	\$ (0.66)
PENELEC	\$ 0.12	\$ 0.03	\$(0.14)	\$(0.51)	\$ 0.05	\$(0.41)	\$(0.64)	\$(0.44)	\$(0.55)	\$(0.16)	\$(0.11)	\$(0.19)	\$ (0.24)
PEPCO	\$ 0.03	\$ 0.23	\$(0.37)	\$(0.03)	\$ 0.36	\$ 0.03	\$(0.22)	\$(0.05)	\$(0.17)	\$ 0.01	\$(0.37)	\$(0.20)	\$ (0.06)
PLGRP	\$(0.04)	\$(0.15)	\$(0.69)	\$(0.45)	\$(0.04)	\$(0.56)	\$(1.22)	\$(0.80)	\$(0.79)	\$(0.15)	\$(0.31)	\$(0.50)	\$ (0.48)
PSEG	\$(0.16)	\$(0.28)	\$(0.70)	\$(0.45)	\$ 0.05	\$(0.58)	\$(1.49)	\$(1.00)	\$(0.81)	\$(0.08)	\$(0.59)	\$(0.62)	\$ (0.59)
RECO	\$(0.35)	\$(0.88)	\$(1.95)	\$(0.14)	\$ 0.44	\$(0.69)	\$(0.93)	\$(0.71)	\$(0.65)	\$ 0.09	\$(0.81)	\$(0.41)	\$ (0.59)
PJM	\$(0.11)	\$(0.15)	\$(0.25)	\$(0.27)	\$ 0.10	\$(0.19)	\$(0.52)	\$(0.30)	\$(0.31)	\$ 0.09	\$(0.25)	\$(0.18)	\$ (0.20)

Annual Load Payment Savings Due To Artificial Island Solution

- During the peak months of July and August, the market simulation shows a decrease of the monthly load payments across DPL zone of $4.32 million and $3.64 million, respectively.
- The annual total load payments across DPL zone decreases by $17.04 million.
- The PJM annual total load payments decrease by $169.2 million.

Load Payments Savings Due to Artificial Island Solution ($ million, negative value is a benefit, a decrease in load payments)

Area	Month 1	2	3	4	5	6	7	8	9	10	11	12	Annual Total
AECO	$ (0.14)	$ (0.22)	$ (0.67)	$ (0.60)	$ (0.15)	$ (0.70)	$ (2.13)	$ (1.46)	$ (0.91)	$ (0.28)	$ (0.38)	$ (0.64)	$ (8.28)
AEP	$ (2.82)	$ (3.54)	$ (0.13)	$ (0.99)	$ 1.16	$ (0.21)	$ (1.34)	$ (0.17)	$ (1.05)	$ 2.57	$ (1.98)	$ 0.06	$ (8.43)
APS	$ (0.04)	$ (0.84)	$ (1.49)	$ (0.43)	$ 1.48	$ (0.29)	$ (0.97)	$ (0.51)	$ (0.93)	$ 0.73	$ (0.91)	$ (0.28)	$ (4.46)
BGE	$ 0.14	$ 0.39	$ (1.31)	$ (0.50)	$ 0.52	$ (0.35)	$ (1.37)	$ (0.55)	$ (1.29)	$ (0.14)	$ (0.91)	$ (0.83)	$ (6.22)
COMED	$ (2.09)	$ (2.47)	$ 3.78	$ (2.89)	$ (0.71)	$ 0.14	$ (0.49)	$ 0.82	$ 0.08	$ 0.08	$ 4.04	$ 1.41	$ 1.70
DAY	$ (0.52)	$ (0.73)	$ 0.24	$ (0.07)	$ (0.00)	$ (0.02)	$ (0.15)	$ 0.00	$ (0.09)	$ 0.64	$ (0.21)	$ (0.00)	$ (0.92)
DEOK	$ (0.70)	$ (1.04)	$ 0.45	$ (0.28)	$ (0.09)	$ (0.04)	$ (0.22)	$ 0.00	$ (0.10)	$ 1.14	$ (0.24)	$ (0.02)	$ (1.16)
DOM	$ 0.17	$ 2.46	$ (2.86)	$ (0.32)	$ 2.53	$ 0.19	$ (1.58)	$ (0.26)	$ (0.80)	$ 0.57	$ (3.95)	$ (1.49)	$ (5.33)
DPL	$ (0.34)	$ (0.35)	$ (1.35)	$ (0.99)	$ (0.40)	$ (1.30)	$ (4.32)	$ (3.64)	$ (1.66)	$ (0.53)	$ (0.85)	$ (1.32)	$ (17.04)
DUQ	$ (0.22)	$ (0.13)	$ (0.88)	$ (0.43)	$ 0.51	$ (0.21)	$ (0.35)	$ (0.17)	$ 0.15	$ 0.86	$ (1.27)	$ (0.14)	$ (2.26)
EKPC	$ (0.26)	$ (0.39)	$ 0.10	$ 0.01	$ 0.03	$ (0.01)	$ (0.06)	$ 0.65	$ (0.68)	$ 0.23	$ (0.13)	$ (0.01)	$ (0.53)
FE-ATSI	$ (0.44)	$ (1.13)	$ (1.76)	$ (2.03)	$ 1.22	$ (0.89)	$ (1.36)	$ (0.50)	$ (0.23)	$ 2.19	$ (2.96)	$ (0.40)	$ (8.28)
JCPL	$ (0.25)	$ (0.53)	$ (1.37)	$ (0.77)	$ 0.13	$ (1.34)	$ (3.90)	$ (2.52)	$ (1.71)	$ (0.42)	$ (0.75)	$ (1.19)	$ (14.62)
METED	$ 0.00	$ (0.16)	$ (1.08)	$ (0.78)	$ (0.19)	$ (0.88)	$ (1.80)	$ (1.04)	$ (1.53)	$ (0.31)	$ (0.50)	$ (0.68)	$ (8.96)
PECO	$ (0.39)	$ (0.81)	$ (2.38)	$ (1.99)	$ (0.39)	$ (2.35)	$ (7.56)	$ (5.05)	$ (3.20)	$ (0.72)	$ (1.33)	$ (2.32)	$ (28.46)
PENELEC	$ 0.22	$ 0.04	$ (0.24)	$ (0.79)	$ 0.08	$ (0.65)	$ (1.09)	$ (0.76)	$ (0.88)	$ (0.26)	$ (0.18)	$ (0.34)	$ (4.87)
PEPCO	$ 0.08	$ 0.59	$ (0.95)	$ (0.07)	$ 0.91	$ 0.07	$ (0.73)	$ (0.15)	$ (0.45)	$ 0.04	$ (0.89)	$ (0.55)	$ (2.10)
PLGRP	$ (0.15)	$ (0.55)	$ (2.58)	$ (1.49)	$ (0.12)	$ (2.00)	$ (4.72)	$ (3.09)	$ (2.70)	$ (0.50)	$ (1.08)	$ (2.00)	$ (20.97)
PSEG	$ (0.61)	$ (0.96)	$ (2.54)	$ (1.50)	$ 0.20	$ (2.40)	$ (6.98)	$ (4.55)	$ (3.11)	$ (0.29)	$ (2.02)	$ (2.33)	$ (27.10)
RECO	$ (0.04)	$ (0.10)	$ (0.23)	$ (0.02)	$ 0.05	$ (0.10)	$ (0.15)	$ (0.11)	$ (0.09)	$ 0.01	$ (0.09)	$ (0.05)	$ (0.92)
PJM	$ (3.40)	$ (10.46)	$ (17.24)	$ (16.88)	$ 6.77	$ (13.35)	$ (41.29)	$ (23.66)	$ (20.57)	$ 5.61	$ (16.58)	$ (13.13)	$ (169.20)

Distribution Factor Allocations

DFAX ALLOCATIONS WITH AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.7%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.5%	0.0%	0.0%	47.0%	1.9%
Salem - Hope Creek	22.8%	1.1%	0.0%	0.0%	41.4%	4.4%	0.0%	0.0%	0.0%	0.0%	29.1%	1.2%
Salem - Orchard	8.2%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.6%	0.0%	0.0%	46.5%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	17.1%	2.0%	1.5%	20.6%	0.0%	0.0%	54.9%	2.2%
Hope Creek - New Freedom	7.7%	0.0%	0.0%	1.3%	16.8%	1.8%	1.2%	22.4%	0.0%	0.0%	47.0%	1.9%
Hope Creek - Red Lion	1.9%	36.0%	29.4%	1.2%	3.2%	0.3%	1.7%	0.0%	0.0%	26.3%	0.0%	0.0%

DFAX ALLOCATIONS WITHOUT AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.6%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	22.9%	0.0%	0.0%	46.8%	1.9%
Salem - Hope Creek	21.2%	3.8%	7.7%	0.0%	41.2%	4.4%	0.0%	0.0%	0.0%	0.0%	20.9%	0.9%
Salem - Orchard	8.1%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	23.1%	0.0%	0.0%	46.2%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	16.9%	2.0%	1.5%	21.0%	0.0%	0.0%	54.7%	2.2%
Hope Creek - New Freedom	7.6%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.8%	0.0%	0.0%	46.7%	1.9%
Hope Creek - Red Lion	0.6%	26.1%	51.6%	0.9%	1.1%	0.1%	1.3%	0.0%	0.1%	18.3%	0.0%	0.0%

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August 10, 2015

Mr. Howard Schneider
Chair
Board of Managers
PJM Interconnection, L.L.C.
P.O. Box 1525
Southeastern, PA 19399-1525

Subject: Supplemental Comments of Easton Utilities on PJM Staff Artificial Island Recommendation

Dear Mr. Schneider:

Easton Utilities Commission ("Easton"), is a municipal utility and PJM Member located in the Delmarva Power and Light Company ("DPL") Transmission Zone of PJM. The purpose of this letter is to express Easton's concern regarding the proposed allocation of the costs of the Artificial Island ("AI") solution approved by the PJM Board of Managers on July 29, 2015. From the materials posted, it appears that, if the costs of the AI solution are allocated in the manner recommended by PJM Staff, the DPL Zone would bear nearly 90% of the solution's total costs. In Easton's view, that outcome is unreasonable and inequitable for at least two reasons.

First, the benefits of the AI solution will be spread over a much larger area than the DPL Zone. As Terry Boston's July 29 letter to the PJM Members Committee points out, the purpose of the AI solution is to resolve stability and voltage issues that have affected use of the 3,818 MW of generation in the AI located in southern New Jersey. Those operational issues have, in the words of PJM's Project Recommendation White Paper, "present[ed] PJM and PSE&G system operators with limited solutions for remaining within prescribed operating limits to maintain reliability." Resolution of such issues benefits the PJM region as a whole because an unexpected loss of the AI generation could have operational impacts for the entire PJM footprint. It is plainly inequitable to require consumers within the DPL Zone to bear 90% of the cost of improvements that are intended to provide system reliability benefits over a far larger area.

Second, the proposed allocation of costs is not justified by any incidental LMP benefits produced by the AI approved solution. In fact, PJM Staff's analysis of the AI solution's market efficiency benefits shows that the costs that would be allocated to the DPL Zone are more than twice the load payment savings the DPL Zone might hope to enjoy as a result. Indeed, that analysis also indicates that the DPL Zone would receive only about 10% of the total forecasted annual load payment savings produced by the AI solution. Again, Easton views it as unreasonable to assign nearly 90% of the AI solution's cost to the DPL Zone when the vast bulk of the load payment savings will be enjoyed by end-users in other transmission zones.

The inequitable nature of the AI solution's cost allocation should not be dismissed with the claim that "PJM must follow its Tariff." Without offering a view as to whether the PJM Tariff necessarily produces the allocation described above, Easton points out that PJM has, on a number of occasions, obtained FERC's permission to waive parts of its Tariff when doing so was deemed warranted to avoid an unreasonable or inequitable outcome. The AI solution appears to present just such a circumstance. Therefore, if PJM concludes that its Tariff requires the above-described allocation of costs, Easton urges PJM to consider seeking a waiver of the applicable Tariff provisions, in order to avoid imposing unjust and unreasonable burdens on consumers on the Delmarva Peninsula in the DPL Transmission Zone.

Sincerely,

A.R. Boughner Jr

Arnold R. Boughner, Jr.
Manager, Electric Department
Easton Utilities

ARB/cwb

cc: Hugh E. Grunden
Geoffrey F. Oxnam
Steven J. Ochse
Gary J. Newell

AI Complaint Appendix 4: Mkt Efficiency Study

PJM Market Efficiency Study
Artificial Island Benefits

Requested by Delaware Public Service Commission

Study Assumptions

Market Efficiency Project Study approach:

- Utilized PJM Market Efficiency Base Case for study year 2019

- Compared LMP and Load Payments between the following scenarios for both a single hour* and annual value:
  - System without Artificial Island solution and one Salem Unit Offline**
  - System with Artificial Island solution and all Salem Units Online

* *Single hour derived from RTO* Coincident Peak using 2019 Base Simulation
***Annual assumes one Salem unit offline for entire simulated year.*

Results using RTO Coincident Peak Hour

- RTO Coincident Peak hour from simulation: July 31, 2019
- RTO Peak Load from simulation: 155,382 MWs

- Simulation results show that the Artificial Island project decreases LMP in Delmarva Zone (DPL) for the Peak hour by $3.5/MWh and Load Payments by $13,772/h.
  - Base case assumes no Artificial Island solution and one Salem Unit offline.

Annual LMP Benefits Due To Artificial Island Solution*

- During the peak months of July and August, the market simulation shows an average LMP decrease in DPL Zone of 2.20 $/MWh and 1.90 $/MWh, respectively.
- The annual LMP average across DPL decreases by 0.86 $/MWh.
- The PJM average LMP decreases by 0.52 $/MWh in July, and 0.30 $/MWh in August.

LMP Avg. Benefits Due to Artificial Island Solution (negative value is a benefit, a decrease in LMP)

Area	Month												
	1	2	3	4	5	6	7	8	9	10	11	12	Annual Average
AECO	$(0.15)	$(0.26)	$(0.82)	$(0.80)	$(0.18)	$(0.72)	$(1.79)	$(1.27)	$(1.01)	$(0.35)	$(0.48)	$(0.71)	$ (0.77)
AEP	$(0.23)	$(0.32)	$(0.01)	$(0.10)	$ 0.11	$(0.02)	$(0.11)	$(0.01)	$(0.10)	$ 0.25	$(0.19)	$ 0.01	$ (0.06)
APS	$(0.01)	$(0.19)	$(0.35)	$(0.11)	$ 0.38	$(0.07)	$(0.22)	$(0.11)	$(0.24)	$ 0.18	$(0.23)	$(0.06)	$ (0.09)
BGE	$ 0.04	$ 0.14	$(0.47)	$(0.20)	$ 0.20	$(0.12)	$(0.41)	$(0.17)	$(0.47)	$(0.06)	$(0.35)	$(0.28)	$ (0.18)
COMED	$(0.22)	$(0.29)	$ 0.44	$(0.36)	$(0.08)	$ 0.02	$(0.05)	$ 0.08	$ 0.01	$ 0.01	$ 0.48	$ 0.15	$ 0.02
DAY	$(0.31)	$(0.49)	$ 0.16	$(0.05)	$(0.00)	$(0.01)	$(0.09)	$ 0.00	$(0.06)	$ 0.44	$(0.15)	$(0.00)	$ (0.05)
DEOK	$(0.28)	$(0.47)	$ 0.20	$(0.14)	$(0.04)	$(0.02)	$(0.08)	$ 0.00	$(0.05)	$ 0.53	$(0.11)	$(0.01)	$ (0.04)
DOM	$ 0.02	$ 0.28	$(0.33)	$(0.04)	$ 0.31	$ 0.02	$(0.16)	$(0.03)	$(0.09)	$ 0.07	$(0.47)	$(0.16)	$ (0.05)
DPL	$(0.19)	$(0.22)	$(0.85)	$(0.70)	$(0.27)	$(0.77)	$(2.20)	$(1.90)	$(1.05)	$(0.36)	$(0.57)	$(0.77)	$ (0.86)
DUQ	$(0.16)	$(0.10)	$(0.69)	$(0.37)	$ 0.42	$(0.15)	$(0.23)	$(0.12)	$ 0.12	$ 0.70	$(1.04)	$(0.10)	$ (0.14)
EKPC	$(0.22)	$(0.38)	$ 0.11	$ 0.01	$ 0.03	$(0.01)	$(0.06)	$ 0.05	$(0.09)	$ 0.27	$(0.14)	$(0.01)	$ (0.05)
FE-ATSI	$(0.07)	$(0.20)	$(0.30)	$(0.38)	$ 0.22	$(0.15)	$(0.21)	$(0.08)	$(0.04)	$ 0.40	$(0.54)	$(0.07)	$ (0.12)
JCPL	$(0.12)	$(0.28)	$(0.71)	$(0.44)	$ 0.07	$(0.61)	$(1.52)	$(1.02)	$(0.85)	$(0.23)	$(0.41)	$(0.58)	$ (0.59)
METED	$ 0.00	$(0.12)	$(0.78)	$(0.62)	$(0.15)	$(0.62)	$(1.18)	$(0.69)	$(1.15)	$(0.24)	$(0.38)	$(0.46)	$ (0.54)
PECO	$(0.10)	$(0.24)	$(0.68)	$(0.61)	$(0.12)	$(0.63)	$(1.79)	$(1.23)	$(0.91)	$(0.22)	$(0.40)	$(0.63)	$ (0.66)
PENELEC	$ 0.12	$ 0.03	$(0.14)	$(0.51)	$ 0.05	$(0.41)	$(0.64)	$(0.44)	$(0.55)	$(0.16)	$(0.11)	$(0.19)	$ (0.24)
PEPCO	$ 0.03	$ 0.23	$(0.37)	$(0.03)	$ 0.36	$ 0.03	$(0.22)	$(0.05)	$(0.17)	$ 0.01	$(0.37)	$(0.20)	$ (0.06)
PLGRP	$(0.04)	$(0.15)	$(0.69)	$(0.45)	$(0.04)	$(0.56)	$(1.22)	$(0.80)	$(0.79)	$(0.15)	$(0.31)	$(0.50)	$ (0.48)
PSEG	$(0.16)	$(0.28)	$(0.70)	$(0.45)	$ 0.05	$(0.58)	$(1.49)	$(1.00)	$(0.81)	$(0.08)	$(0.59)	$(0.62)	$ (0.59)
RECO	$(0.35)	$(0.88)	$(1.95)	$(0.14)	$ 0.44	$(0.69)	$(0.93)	$(0.71)	$(0.65)	$ 0.09	$(0.81)	$(0.41)	$ (0.59)
PJM	$(0.11)	$(0.15)	$(0.25)	$(0.27)	$ 0.10	$(0.19)	$(0.52)	$(0.30)	$(0.31)	$ 0.09	$(0.25)	$(0.18)	$ (0.20)

*Simulation assumes one Salem unit offline for entire year.

Annual Load Payment Savings Due To Artificial Island Solution*

- During the peak months of July and August, the market simulation shows a decrease of the monthly load payments across DPL zone of $4.32 million and $3.64 million, respectively.
- The annual total load payments across DPL zone decreases by $17.04 million.
- The PJM annual total load payments decrease by $169.2 million.

Load Payments Savings Due to Artificial Island Solution ($ million, negative value is a benefit, a decrease in load payments)												
Area	Month											
	1	2	3	4	5	6	7	8	9	10	11	12	Annual Total
AECO	$ (0.14)	$ (0.22)	$ (0.67)	$ (0.60)	$ (0.15)	$ (0.73)	$ (2.13)	$ (1.46)	$ (0.91)	$ (0.28)	$ (0.38)	$ (0.64)	$ (8.28)
AEP	$ (2.82)	$ (3.54)	$ (0.13)	$ (0.99)	$ 1.16	$ (0.21)	$ (1.34)	$ (0.17)	$ (1.05)	$ 2.57	$ (1.98)	$ 0.06	$ (8.43)
APS	$ (0.04)	$ (0.84)	$ (1.49)	$ (0.43)	$ 1.48	$ (0.29)	$ (0.97)	$ (0.51)	$ (0.93)	$ 0.73	$ (0.91)	$ (0.28)	$ (4.46)
BGE	$ 0.14	$ 0.39	$ (1.31)	$ (0.50)	$ 0.52	$ (0.35)	$ (1.37)	$ (0.55)	$ (1.29)	$ (0.14)	$ (0.91)	$ (0.83)	$ (5.22)
COMED	$ (2.09)	$ (2.47)	$ 3.78	$ (2.89)	$ (0.71)	$ 0.14	$ (0.49)	$ 0.82	$ 0.08	$ 0.08	$ 4.04	$ 1.41	$ 1.70
DAY	$ (0.52)	$ (0.73)	$ 0.24	$ (0.07)	$ (0.00)	$ (0.02)	$ (0.15)	$ 0.00	$ (0.09)	$ 0.64	$ (0.21)	$ (0.00)	$ (0.92)
DEOK	$ (0.70)	$ (1.04)	$ 0.45	$ (0.28)	$ (0.09)	$ (0.04)	$ (0.22)	$ 0.00	$ (0.10)	$ 1.14	$ (0.24)	$ (0.02)	$ (1.16)
DOM	$ 0.17	$ 2.46	$ (2.86)	$ (0.32)	$ 2.53	$ 0.19	$ (1.58)	$ (0.26)	$ (0.80)	$ 0.57	$ (3.95)	$ (1.49)	$ (5.33)
DPL	$ (0.34)	$ (0.35)	$ (1.35)	$ (0.99)	$ (0.40)	$ (1.30)	$ (4.32)	$ (3.64)	$ (1.66)	$ (0.53)	$ (0.85)	$ (1.32)	$ (17.04)
DUQ	$ (0.22)	$ (0.13)	$ (0.88)	$ (0.43)	$ 0.51	$ (0.21)	$ (0.35)	$ (0.17)	$ 0.15	$ 0.36	$ (1.27)	$ (0.14)	$ (2.26)
EKPC	$ (0.26)	$ (0.39)	$ 0.10	$ 0.01	$ 0.03	$ (0.01)	$ (0.06)	$ 0.65	$ (0.08)	$ 0.23	$ (0.13)	$ (0.01)	$ (0.53)
FE-ATSI	$ (0.44)	$ (1.13)	$ (1.76)	$ (2.03)	$ 1.22	$ (0.89)	$ (1.36)	$ (0.50)	$ (0.23)	$ 2.19	$ (2.96)	$ (0.40)	$ (8.28)
JCPL	$ (0.25)	$ (0.53)	$ (1.37)	$ (0.77)	$ 0.13	$ (1.34)	$ (3.90)	$ (2.52)	$ (1.71)	$ (0.42)	$ (0.75)	$ (1.19)	$ (14.62)
METED	$ 0.00	$ (0.16)	$ (1.08)	$ (0.78)	$ (0.19)	$ (0.88)	$ (1.80)	$ (1.04)	$ (1.53)	$ (0.31)	$ (0.50)	$ (0.68)	$ (8.96)
PECO	$ (0.39)	$ (0.81)	$ (2.38)	$ (1.93)	$ (0.39)	$ (2.35)	$ (7.56)	$ (5.05)	$ (3.20)	$ (0.72)	$ (1.33)	$ (2.32)	$ (28.46)
PENELEC	$ 0.22	$ 0.04	$ (0.24)	$ (0.79)	$ 0.08	$ (0.65)	$ (1.09)	$ (0.76)	$ (0.88)	$ (0.26)	$ (0.18)	$ (0.34)	$ (4.87)
PEPCO	$ 0.08	$ 0.59	$ (0.95)	$ (0.07)	$ 0.91	$ 0.07	$ (0.73)	$ (0.15)	$ (0.45)	$ 0.04	$ (0.89)	$ (0.55)	$ (2.10)
PLGRP	$ (0.15)	$ (0.55)	$ (2.58)	$ (1.49)	$ (0.12)	$ (2.00)	$ (4.72)	$ (3.09)	$ (2.70)	$ (0.50)	$ (1.08)	$ (2.00)	$ (20.97)
PSEG	$ (0.61)	$ (0.96)	$ (2.54)	$ (1.50)	$ 0.20	$ (2.40)	$ (6.98)	$ (4.55)	$ (3.11)	$ (0.29)	$ (2.02)	$ (2.33)	$ (27.10)
RECO	$ (0.04)	$ (0.10)	$ (0.23)	$ (0.02)	$ 0.05	$ (0.10)	$ (0.15)	$ (0.11)	$ (0.09)	$ 0.01	$ (0.09)	$ (0.05)	$ (0.92)
PJM	$ (8.40)	$ (10.46)	$ (17.24)	$ (16.88)	$ 6.77	$ (13.35)	$ (41.29)	$ (23.66)	$ (20.57)	$ 5.61	$ (16.58)	$ (13.13)	$ (169.20)

*Simulation assumes one Salem unit offline for entire year.

Distribution Factor Allocations

DFAX ALLOCATIONS WITH AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.7%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.5%	0.0%	0.0%	47.0%	1.9%
Salem - Hope Creek	22.8%	1.1%	0.0%	0.0%	41.4%	4.4%	0.0%	0.0%	0.0%	0.0%	29.1%	1.2%
Salem - Orchard	8.2%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.6%	0.0%	0.0%	46.5%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	17.1%	2.0%	1.5%	20.6%	0.0%	0.0%	54.9%	2.2%
Hope Creek - New Freedom	7.7%	0.0%	0.0%	1.3%	16.8%	1.8%	1.2%	22.4%	0.0%	0.0%	47.0%	1.9%
Hope Creek - Red Lion	1.9%	36.0%	29.4%	1.2%	3.2%	0.3%	1.7%	0.0%	0.0%	26.3%	0.0%	0.0%

DFAX ALLOCATIONS WITHOUT AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.6%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	22.9%	0.0%	0.0%	46.8%	1.9%
Salem - Hope Creek	21.2%	3.8%	7.7%	0.0%	41.2%	4.4%	0.0%	0.0%	0.0%	0.0%	20.9%	0.9%
Salem - Orchard	8.1%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	23.1%	0.0%	0.0%	46.2%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	16.9%	2.0%	1.5%	21.0%	0.0%	0.0%	54.7%	2.2%
Hope Creek - New Freedom	7.6%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.8%	0.0%	0.0%	46.7%	1.9%
Hope Creek - Red Lion	0.6%	26.1%	51.6%	0.9%	1.1%	0.1%	1.3%	0.0%	0.1%	18.3%	0.0%	0.0%

AI Complaint Appendix 5: April 28 TEAC Presentation

Transmission Expansion Advisory Committee

April 28, 2015

Artificial Island

Agenda

- Stakeholder Comments

- Project Evaluation
  - Performance
  - Cost
  - Constructability

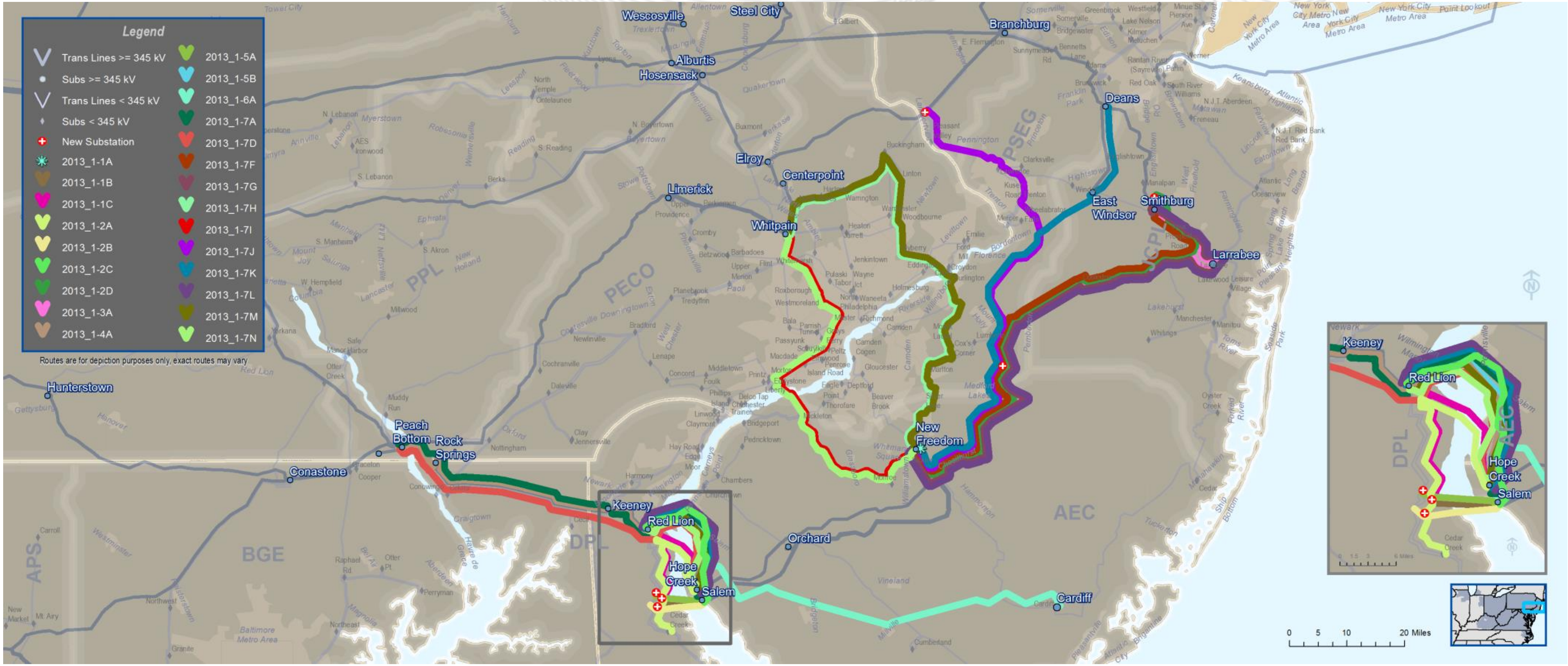
- Artificial Island Project Recommendations

- Next Steps

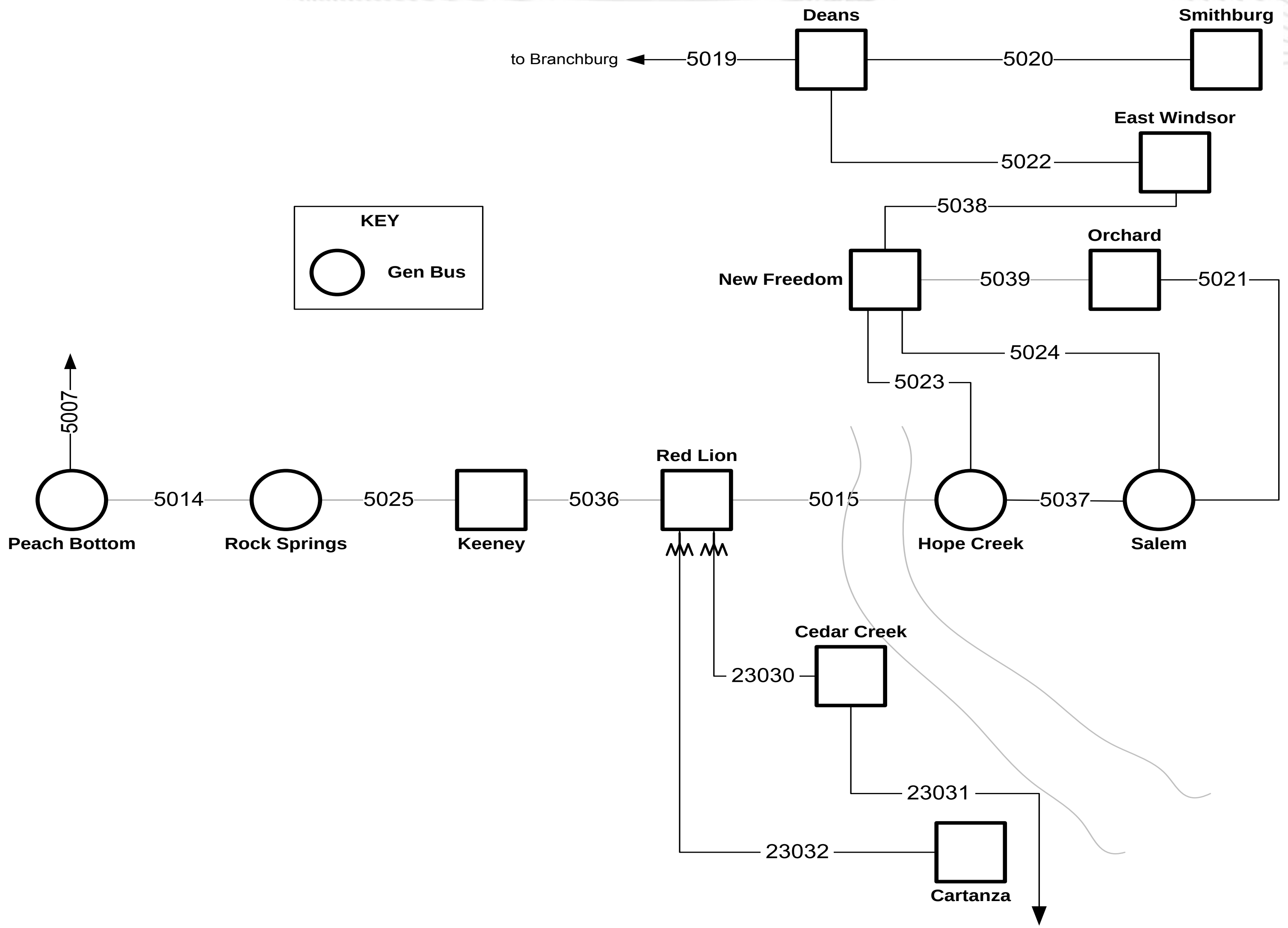
Stakeholder Comments

- Request from Transource and PHI:
  - Has any documentation that materially changes the supplemental information been supplied outside of what is posted on the PJM website?
    - No. Meetings were held with the FERC ALJ to clarify the supplemental information.
  - Requested project scope details for LS Power and PSE&G projects
    - December 9 PJM TEAC, Appendix slides 26 through 35
    - Included in the Appendix of this presentation

Artificial Island Proposals



Artificial Island Area Network

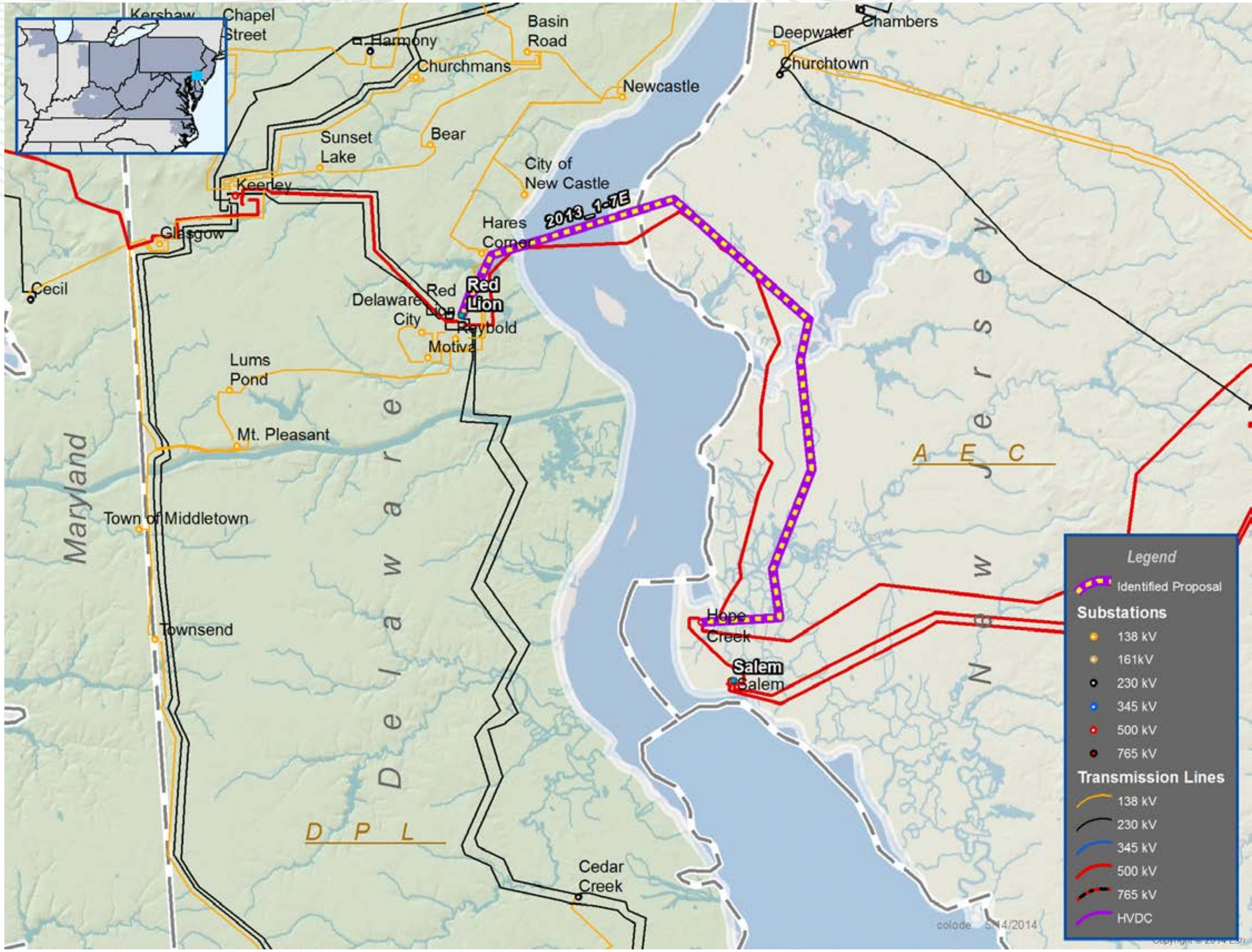


Dominion Virginia Power (DVP) 1A

- New switching station cutting the 5023 and 5024 lines near New Freedom substation that includes
  - 500kV SVC (+750 to -375 MVAr)
  - Two Thyristor Controlled Series Compensation (TCSC) devices

Dominion Virginia Power (DVP) 1C and PSE&G 7K

- Expansion of Hope Creek substation
- 500kV line from Hope Creek to Red Lion
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- Reconfigure Red Lion substation to accommodate new line

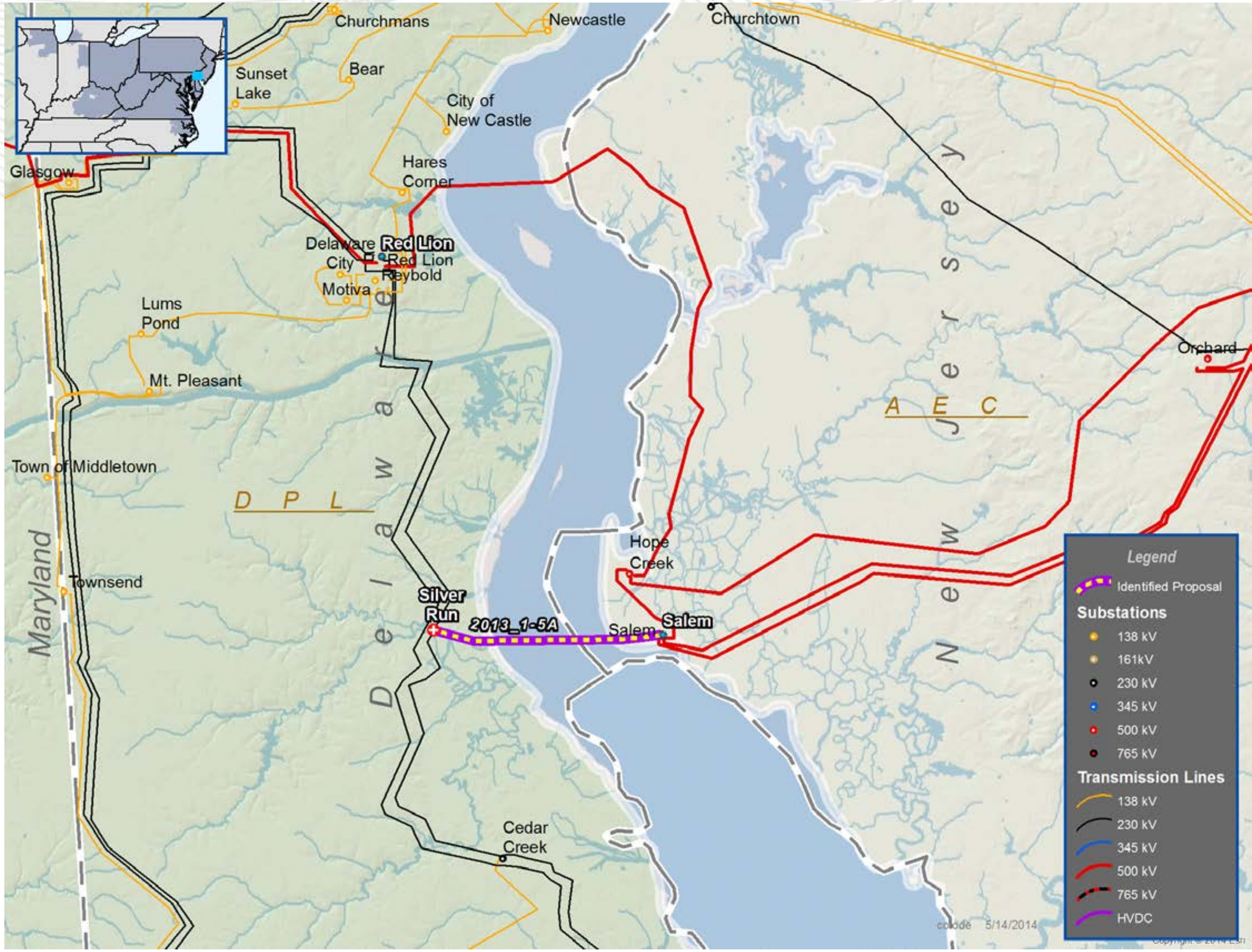


Transource (AEP) 2B

- Expansion of the Salem substation
- New substation near Artificial Island with two 500/230 kV autotransformers
- Submarine line under the Delaware river
- New substation in Delaware that taps the existing Red Lion to Cartanza 230 kV and Red Lion to Cedar Creek 230 kV lines

LS Power 5A

- Expansion of the Salem substation to the south to include a new 500/230kV auto-transformer
- Submarine line under the Delaware
- New substation in Delaware that taps the existing Red Lion to Cartanza 230 kV and Red Lion to Cedar Creek 230 kV lines



Performance

TCSC Study and Analysis

- Siemens Power Technologies International (Siemens PTI) was contracted to perform a Sub Synchronous Resonance screening study of the Dominion 1A proposal

- Siemens SSR Screening Study
  - Available Data
    - Mass moment of inertia and torsional modes
  - Assumptions
    - Approximate two-mass modeling approach
    - Critical conditions (including system configuration and critical faults)
  - Analysis
    - PSCAD simulation and frequency scan
  - Result
    - Negative damping at the Artificial Island for several resonant frequencies

TCSC Study and Analysis

- Exponent's report summary:
  - Determined Siemens SSR study is inconclusive based on the study assumptions
  - The 90% post contingency TCSC compensation level is very high leaving little margin to avoid resonance
    - Identifies that 70-80% compensation is highest in general industry practice
  - To be credible, additional study should consider simulations in a real time digital power system simulation such as RTDS

TCSC Study and Analysis

- Dominion provided a timeline of studies required to design the TCSC controller that estimates 26 weeks for completion
  - Assumptions:
    - All required study data has been acquired
      - This includes the machine data for the nuclear units at Artificial Island
    - Does not include review time between study stages

OPGW and GSU Tap Settings

- Assessment of the impact of reduced fault clearing times and Artificial Island generator step-up transformer tap optimizations on the performance of the proposals:
  - Faster fault clearing times will be realized by installing new line relaying and high speed fiber optic communication channels on several lines
  - PJM analysis quantified the improved stability margins from the relay and GSU tap setting changes

OPGW and GSU Tap Settings

- High speed relaying utilizing OPGW to be implemented on the following existing lines:

5037 Salem – Hope Creek	5022 East Windsor - Deans
5015 Hope Creek – Red Lion	5038 New Freedom – East Windsor
5023 Hope Creek – NF	5024 Salem – New Freedom
5021 Salem - Orchard	5039 New Freedom – Orchard

- Tap setting optimization for the three Artificial Island generator step-up transformers

Margin Testing

- Pushed each project to failure
  - Determined the longest duration fault clearing time (cycles) for which a project remained stable

- PJM Manual 14B
  - Add a ¼ and ½ cycle of fault clearing time and re-test
  - Margin test accounts for uncertainty in actual clearing times

Margin Testing Results – Cycles to Fail

Project	Project ID	Proposing Entity	OPGW Wire	GSU Tap Optimization	TCSC Compensation (Normal/ Transient)	SVC	Outage	Limiting Contingency (redacted)	Maximum Angle Swing	Fault Clearing Time (Tcl) (cycles)	CCT[1] (cycles)	Margin to CCT (cycles) (CCT – Tcl)
230kV	P2013_1-5A	LS Power	Yes		N/A	No	5015		114	9.06[5]	9.31	0.25
						300MVAr	5015		91	9.06	10.31	1.25
			No			650MVAR	5015		112	10.4	10.65	0.25
	P2013_1-2B	Transource	Yes			No	5015		107	9.06	9.56	0.50
						300MVAr	5015		88	9.06	10.56	1.50
			No			650MVAR	5015		109	10.14	10.64	.5
500kV	P2013_1-7K	PSE&G	Yes			No	5015		100	9.06	9.81	0.75
						300MVAr	5015		83	9.06	10.81	1.75
			No			650MVAR	5021		107	4.02	4.27	.25
	P2013_1-1C	DVP	Yes			No	5015		100	9.06	10.06	0.75
						300MVAr	5015		83	9.06	10.81	1.75
			No			650MVAR	5021		107	4.02	4.27	0.25
TCSC only	P2013_1-1A	DVP	Yes		40,45/90%	No	5038		Unstable	2.90	< 2.90	-
TCSC+SVC					40,45/90%	500MVAr	5038		93	2.90	3.15	0.25
					0/50%	750MVAr	5038		99	2.90	2.90	0.00
					0/70%	750MVAr	5038		81	2.90	3.40	0.50

(1) CCT: critical clearing time – maximum fault clearing time for which a system remains transiently stable. In this study CCT resolution is ¼ cycle.
(2) (redacted)
(3) (redacted)
(4) (redacted)
(5) For a SLG fault w/ delayed clearing contingency, back-up clearing time is increased in CCT calculation. Primary clearing time is fixed to 2.90 cycle during the CCT calculation.

Margin Testing Results – M14B Margin Test

Project	Project ID	Proposing Entity	FOG Wire	GSU Tap Optimization	TCSC Compensation (Normal/ Transient)	SVC	Outage	Limiting Contingency (redacted)	Maximum Angle Swing	Margin to CCT (CCTM) (cycles)	M14B Margin (M14B) (cycles)	Margin Results (CCTM-M14B) (cycles)
230kV	P2013_1-5A	LS Power	Yes		N/A	No	5015		114	0.25	0.5	-0.25
						300MVAr	5015		91	1.25	0.5	**0.75**
			No			650MVAR	5015		112	0.25	0.5	-0.25
	P2013_1-2B	Transource	Yes			No	5015		107	0.50	0.5	0.0
						300MVAr	5015		88	1.50	0.5	**1.0**
			No			650MVAR	5015		109	0.50	0.5	0.0
500kV	P2013_1-7K	PSE&G	Yes			No	5015		100	0.75	0.5	**0.25**
						300MVAr	5015		83	1.75	0.5	**1.25**
			No			650MVAR	5021		107	0.25	0.25	0.0
	P2013_1-1C	DVP	Yes			No	5015		100	1.00	0.5	**0.25**
						300MVAr	5015		83	1.75	0.5	**1.25**
			No			650MVAR	5021		107	0.25	0.25	0.0
TCSC only	P2013_1-1A	DVP	Yes		40,45/90%	No	5038		Unstable			
TCSC+SVC					40,45/90%	500MVAr	5038		93	0.25	0.25	0.0
					0/50%	750MVAr	5038		99	0.00	0.25	-0.25
					0/70%	750MVAr	5038		81	0.50	0.25	**0.25**

(1) CCT: critical clearing time – maximum fault clearing time for which a system remains transiently stable. In this study CCT resolution is ¼ cycle.
(2) (redacted)
(3) (redacted)
(4) (redacted)
(5) For a SLG fault w/ delayed clearing contingency, back-up clearing time is increased in CCT calculation. Primary clearing time is fixed to 2.90 cycle during the CCT calculation.

Dominion 1A
Project Evaluation

- SSR and control interaction study duration
  - Six month study duration does not account for data acquisition time
  - If measured data required, acquisition timeframe tied to Artificial Island unit outages
- Compensation
  - Proposed 90% compensation level well above industry norms of 70-80%
- Performance
  - Baseline performance with 90% compensation level and very large SVC is in line with other projects
  - Performance at lower compensation levels not as good as line solutions
  - Performance under margin testing is less robust than line solutions
- Due to the above, the TCSC project is not recommended

Proposed Cost Commitments and Project Cost Estimates

Cost Commitment / Containment Mechanism Summary

Proposing Entity	LS Power	PSE&G	Transource	Dominion
Summary of Terms and Conditions (as specified by the Proposing Entity)	Includes all project costs; exceptions below: 1. PJM scope changes 2. Breach/default of DEA/ICA by PJM 3. Breach / Default / interference or failure to cooperate with ICA Terms by TO 4. Costs caused by changes in laws or regulations	Includes all project costs; exceptions below: 1. PJM scope changes 2. Non-construction project cost changes deemed outside of the control of PSE&G 3. Commitment includes all escalation cost	Includes all project costs; no exceptions 1. Up to $203 million: all ROE / incentives 2. $243 to $299.8 million: half ROE / incentives 3. Above $299.8 million: forego all ROE / incentives	No cost commitment proposed

Cost Estimates Incorporating Cost Commitments

- Total cost estimates combine Proposing Entity cost commitment numbers with PJM cost estimates
  - Costs estimates provided by Proposing Entities for project components within their cost commitment
  - PJM cost estimates used for project components outside of proposed cost commitment

Cost Estimates Incorporating Cost Commitments

Line Projects Coupled with SVC and OPGW/GSU TAP Projects

In Current Year Dollars

Dominion 1C 500kV Line Hope Creek to Red Lion	
Cost Containment	$0
Project Cost Estimate	$211 - $257
OPGW/GSU Taps	$20[1]
SVC Cost Estimate	$31 - $38
Project Total	$263 - $316

PSE&G 7K 500kV Line Hope Creek to Red Lion	
Cost Containment	$221
Red Lion Expansion	$4 - $6
OPGW/GSU Taps	$20[1]
SVC Cost Estimate	$31 - $38
Project Total	$277 - $285

Transource 2B 230kV Submarine	
Cost Containment	$203 - $259
New Salem Substation	$41
Salem Expansion	$14 - $17
OPGW/GSU Taps	$25
SVC Cost Estimate	$31 - $38
Project Total	$313 - $380

LS Power 5A 230kV Submarine	
Cost Containment	$146
Salem Expansion	$61 - $74
OPGW/GSU Taps	$25
SVC Cost Estimate	$31 - $38
Project Total	$263 - $283

[1] Cost for OPGW upgrade work is reduced for 1C and 7K because new line construction includes OPGW

Cost Estimates Incorporating Cost Commitments

Line Projects Coupled with SVC and OPGW/GSU TAP Projects

In-Service Year Dollar Costs (2.5% per year escalation)

Dominion 1C 500kV Line Hope Creek to Red Lion	
Capital Cost (current year $)	
Project Total	$263 - $316
Capital Cost (with escalation)	
Project Total	$284 - $341

Transource 2B 230kV Submarine	
Capital Cost (current year $)	
Project Total	$313 - $380
Capital Cost (with escalation)	
Project Total	$346 - $411

PSE&G 7K 500kV Line Hope Creek to Red Lion	
Capital Cost (current year $)	
Project Total	$277 - $285[1]
Capital Cost (with escalation)	
Project Total	$281 - $290[1]

LS Power 5A 230kV Submarine	
Capital Cost (current year $)	
Project Total	$263 - $283[1]
Capital Cost (with escalation)	
Project Total	$284 - $306[1]

[1] Cost estimates do not capture the risk of cost commitment exclusions discussed on slide 27, 'Cost Containment Comparison'

Transource 2B and Dominion 1C
Project Evaluations

Transource 2B

- Due to the high estimated cost relative to the other projects under consideration, the Transource 2B project is not recommended at this time

Dominion 1C

- Due to the high estimated cost relative to the other projects under consideration and the lack of a cost commitment the Dominion 1C project is not recommended at this time

Cost Containment Comparison

Proposing Entity / Cost Containment Provision	LS Power	PSE&G
Escalation	Costs would be escalated against an industry standard index	Commitment includes all escalation cost
Exclusions to the cost commitment	• PJM project scope changes • Costs caused by changes in laws or regulations • Cost caused by PJM's breach or default • Cost caused by any Transmission Owner breach, default interference or failure to cooperate	• PJM project scope changes • Costs caused by changes in laws or regulations • Greater than anticipated environmental mitigation costs • Costs caused by route changes driven from permitting or land acquisition • Costs incurred due to delays in permit issuance • Cost incurred due to delays incurred due to a court order or action

Cost Estimate Comparisons

- Current Year Dollars
  - LS Power 5A project cost commitment, which is based on current year dollars and tied to an industry escalation index, has lower cost in current year dollars
- In Service Year Dollars
  - PSE&G 7K project cost commitment, which is based on a guaranteed maximum price with escalation included, may have lower cost based on in-service year dollars
- Cost Cap Terms and Conditions
  - Entities will collect revenues based on actual costs
  - LS Power terms and conditions provide fewer exclusions in comparison to the PSE&G terms and conditions
  - Greater potential for increased costs with the PSE&G proposal due to cost containment exceptions

Constructability Analysis

Permitting Risk

Meetings with Permitting Agencies

- PJM met with permitting agencies
  - U.S. Army Corps of Engineers (USACE)
  - Delaware Department of Natural Resource and Environmental Control (DNREC)
  - New Jersey DEP
  - U.S. Fish and Wildlife Service (USFWS)
  - National Marine Fisheries
  - National Oceanic and Atmospheric Administration (NOAA)

Permitting Risk
Meetings with Permitting Agencies

- Feedback is based on preliminary information
  - Without detailed design and route, agencies will not state likelihood of permitting success of any of the projects
  - Various permitting agencies will be involved in review of the project proposals based on the preliminary project information
- Various entities will coordinate review through the lead agency
  - USACE is likely to be the lead agency

Permitting Risk
Meetings with Permitting Agencies

- River Crossing will be major challenge for all projects
  - Type of construction will impact permitting
    - Overhead
    - Jet-plow
    - Horizontal directional drilling
  - Issues will include:
    - View shed
    - Burial depth
    - Construction time
    - Navigational impacts
    - Use of existing RoW
- Permitting through the sensitive environmental areas may be difficult
  - Supawna Meadows National Wildlife Refuge
  - Augustine Wildlife Area

Evaluation Considerations

- Primary Considerations
  - Technical Analysis
    - Thermal
    - Stability
    - Short-circuit
    - Voltage
    - NERC Cat-D Contingencies
  - Cost Factors
    - Cost Commitments
    - Cost effectiveness
    - Market efficiency
    - PJM estimated costs
- Secondary Considerations
  - Schedule
    - Permitting
    - Construction
    - Long lead time equipment
  - Project Complexity
    - Line crossings
    - Outage requirements
    - Modifications to other transmission facilities
    - Modification to Artificial Island substations
    - Modifications to Red Lion substation
  - Right of Way and Land Acquisition
    - New right of way required
    - Substation land required
  - Siting and Permitting
    - Wetlands impact
    - Public opposition risk
    - Delaware river crossing
    - Land permitting
    - Historic and scenic highway
  - Operational Impact
    - Artificial island facility requirements
    - Ongoing maintenance
    - Blackstart
    - Route diversity
    - Operational Robustness

Project Complexity

- Outage Requirements
  - Artificial Island to Red Lion solutions would require outages to the 5015 line
    - 5015 line outages are challenging to schedule
  - All projects would require coordination of 500kV and 230kV facility outages
  - PJM operational analysis to manage impact to system configuration to support any outage required to support construction
    - Reactive devices
    - Coordination with planned generation and transmission outages

- A solution that minimizes outage requirements during construction is preferred

Siting and Permitting

- Land Permitting
  - All projects will face challenges
    - Red Lion to Artificial Island
      - State wildlife management areas
      - Supawna Meadows National Wildlife Refuge
        - » Permitting may be made more difficult with the availability of a viable alternative
    - Southern crossing lines
      - Augustine Wildlife Area
        - » Permitting may be made more difficult with the availability of a viable alternative
        - » Potentially mitigated through HDD and route selection

- A solution that can mitigate land permitting is preferred

Siting and Permitting

- Delaware River Crossing
  - Type of construction will impact permitting
    - Overhead
    - Jet-plow
    - Horizontal directional drilling (HDD)
  - Issues will include:
    - View shed
    - Burial depth
    - Construction time
    - Navigational impacts
    - Use of existing RoW

- Siting and permitting for a new river crossing will be a major component in the project schedule for all projects under consideration, but there appears to be a lower risk for a NEPA EIS being required for a solution utilizing HDD

Additional Evaluation Considerations

- Blackstart
  - LS Power 5A provides access to additional blackstart resources
- Historic and scenic highway
  - LS Power 5A line parallels Delaware state route 9
- Market efficiency
  - LS Power 5A: $92M over 15 years
  - PSE&G 7K: $57M over 15 years
- Route diversity
  - LS Power 5A project is a new, diverse route
- Salem expansion
  - Constrained with limited space
- Operational robustness
  - PSE&G 7K project improves voltage drop for loss of 500kV facilities
- Wetlands impact
  - PSE&G 7K project potentially impacts approximately 16 acres of forested wetlands
  - LS Power 5A project potentially impacts approximately 8 to 11 acres of forested wetlands
- Construction and long lead time equipment
  - LS Power 5A project construction involves specialized equipment and transmission cable and auto-transformers are long lead time equipment

Artificial Island Recommendation

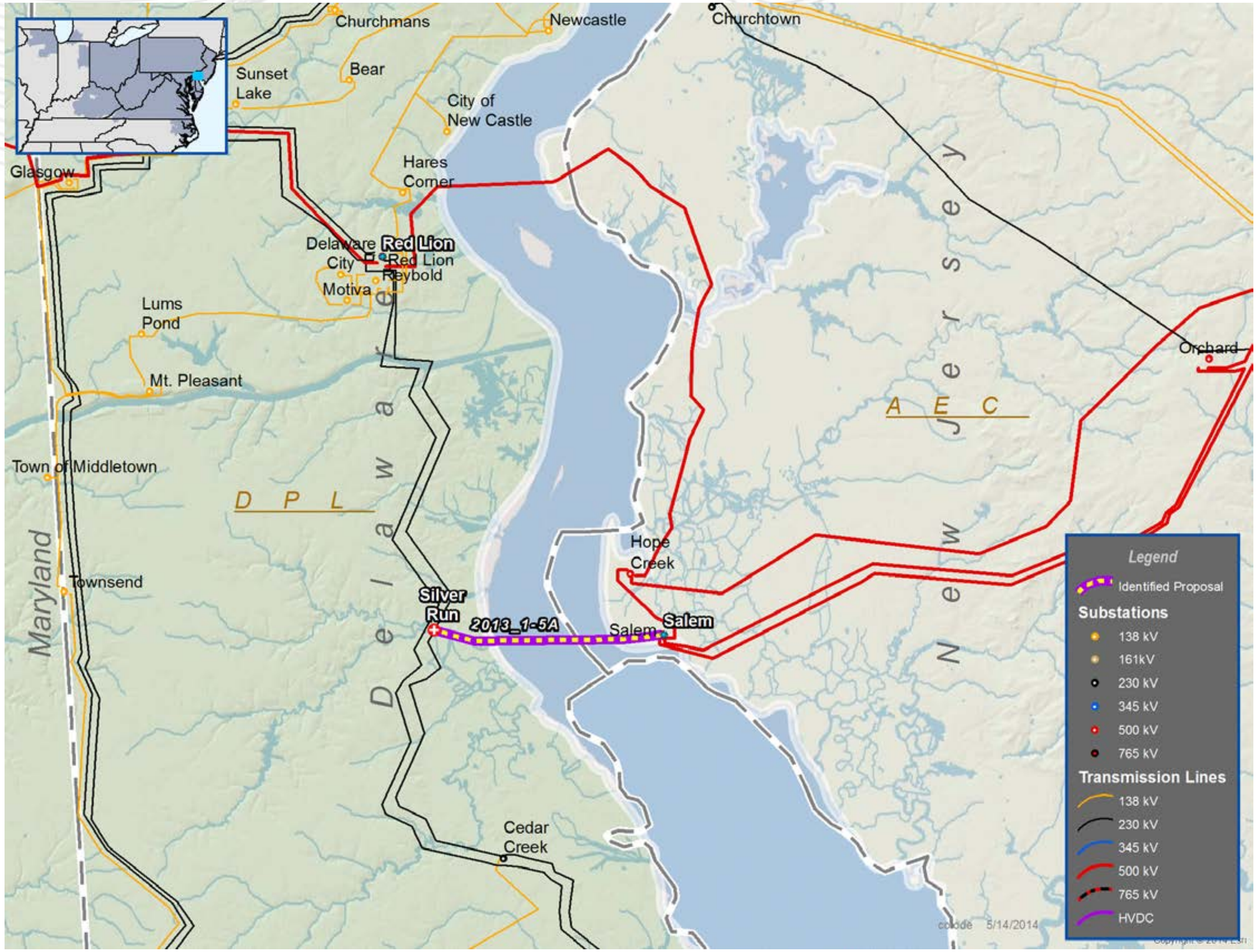
- Performance
  - The line proposals along with a 300MVAR SVC at New Freedom and the protective relay improvements satisfy all requirements of the request for proposal
- Cost
  - The LS Power proposal and the PSE&G proposal are the lowest cost alternatives
  - PJM’s evaluation of the cost commitments finds that the LS Power proposal provides greater cost certainty with fewer exclusions to the cost commitment
- Constructability
  - Siting will be challenging for both line proposals however the LS Power proposal through the use of horizontal directional drilling technology provides greater flexibility to mitigate permitting risk

Artificial Island Recommendation

- At the July 27 PJM Board meeting, PJM staff will recommend for inclusion in the RTEP:
  - 230kV transmission line under the Delaware river from Salem to a new substation near the 230kV transmission RoW in Delaware utilizing HDD under the river designated to LS Power
    - Associated substation work at Salem designated to PSE&G
    - Associated work on the 230kV RoW designated to PHI
  - SVC at New Freedom designated to PSE&G
  - OPGW upgrades designated to PSE&G and PHI
  - Artificial Island GSU tap settings upgrade designated to PSEG Power

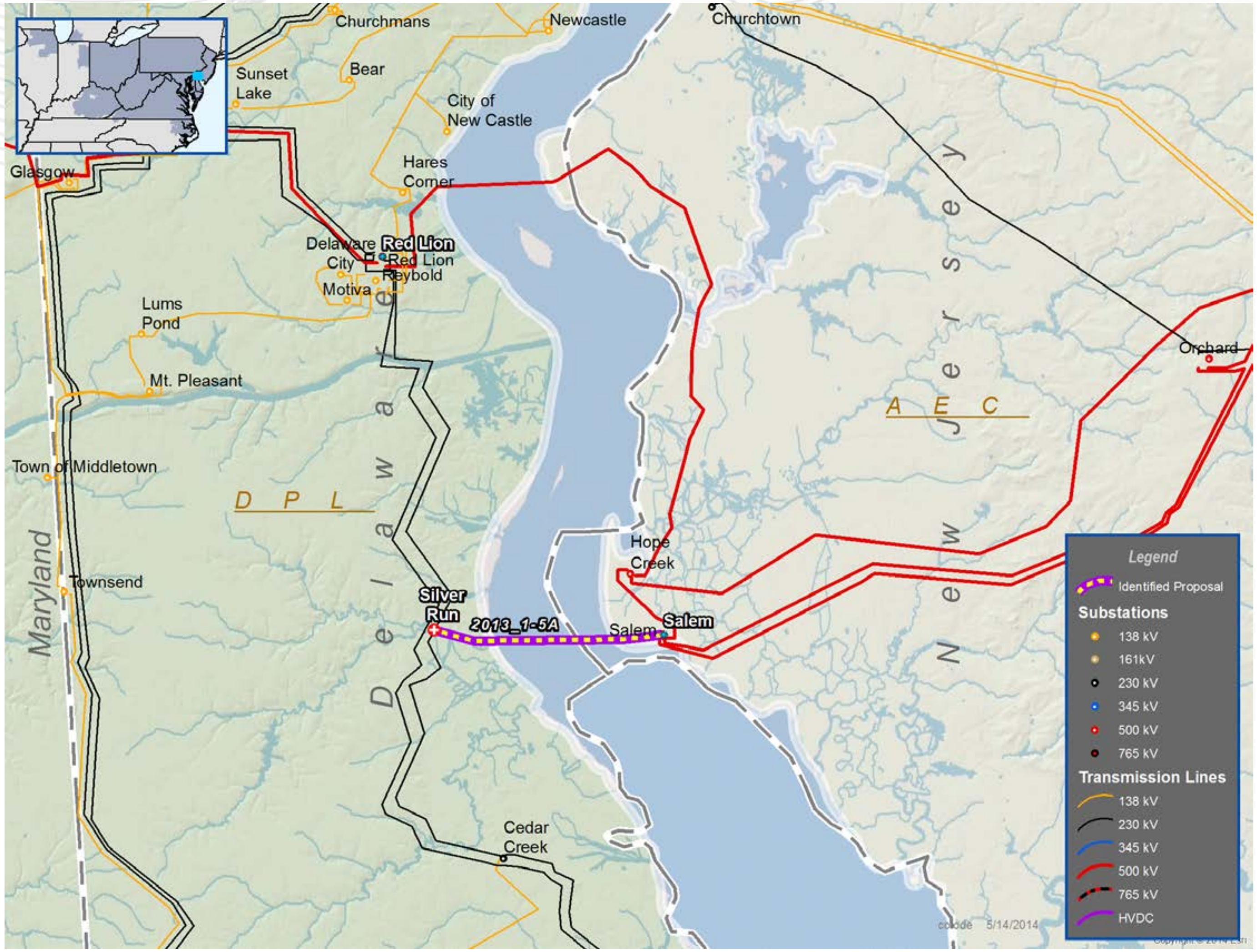
Artificial Island Project Recommendation

- In consideration of all factors, PJM staff will recommend for inclusion in the RTEP:
  - A new 230kV circuit from Salem to a new substation near the 230kV corridor in Delaware tapping the existing Red Lion to Cartanza and Red Lion to Cedar Creek 230 kV lines, utilizing HDD under the river (b2633.1)
  - Designate transmission line to LS Power



Artificial Island Project Recommendation

- Required connection facilities to accommodate the new transmission facilities:
  - Expansion of the Salem substation (b2633.2)
    - Designate to PSE&G
  - Interconnecting to the existing Red Lion to Cartanza and Red Lion to Cedar Creek 230 kV lines into the new substation (b2633.3)
    - Designate to PHI



SVC Upgrade Project Recommendation

- Construct an SVC at New Freedom 500 kV substation
  - Facilities design will determine the final technical parameters (b2633.4)

- Project cost estimate:
  - $31M to $38M

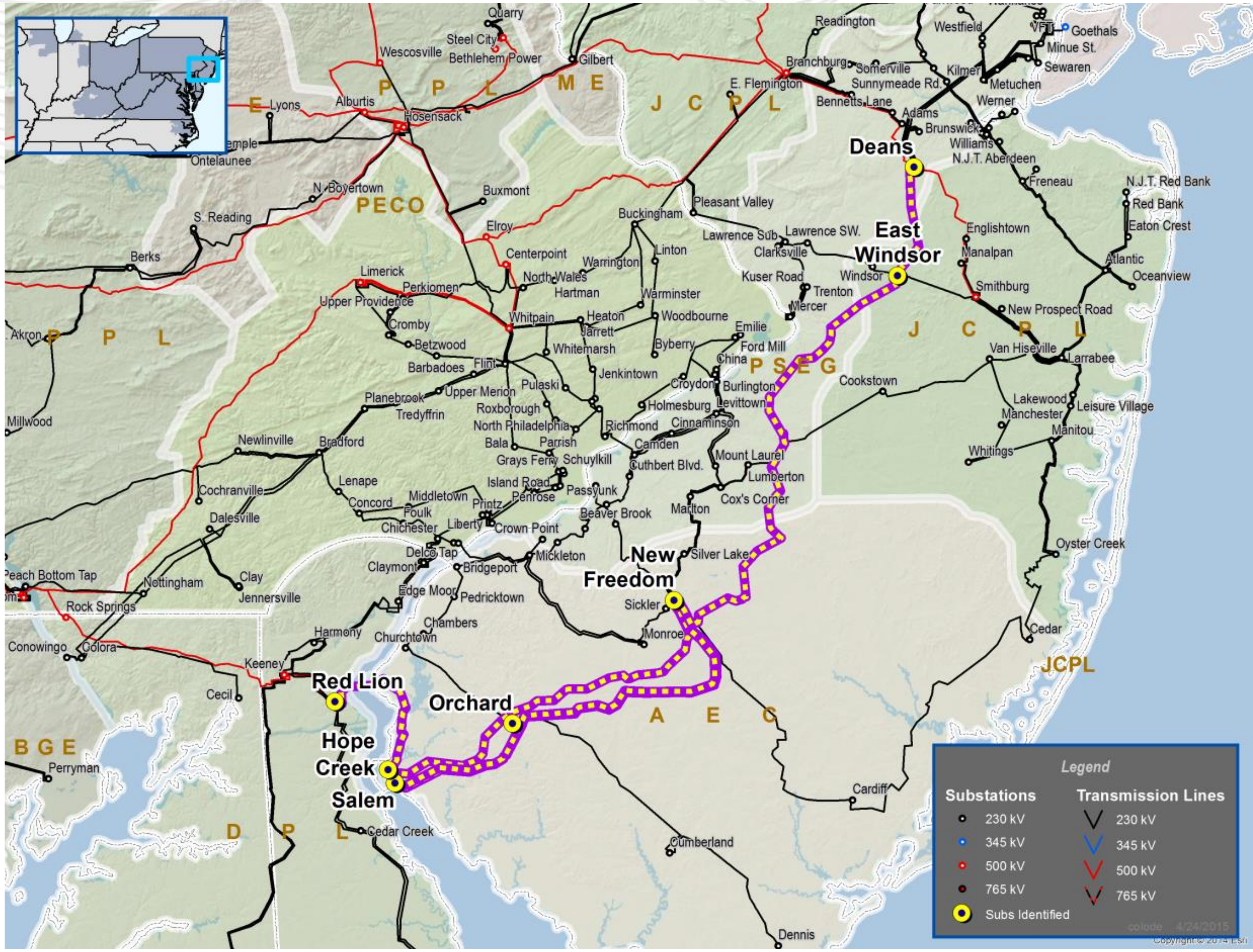
- Designate SVC upgrade at New Freedom to PSE&G

OPGW Upgrade Project Recommendation

- Implement high speed relaying utilizing OPGW on the following existing lines (b2633.5 and b2633.6):

5037	5022
5015	5038
5023	5024
5021	5039

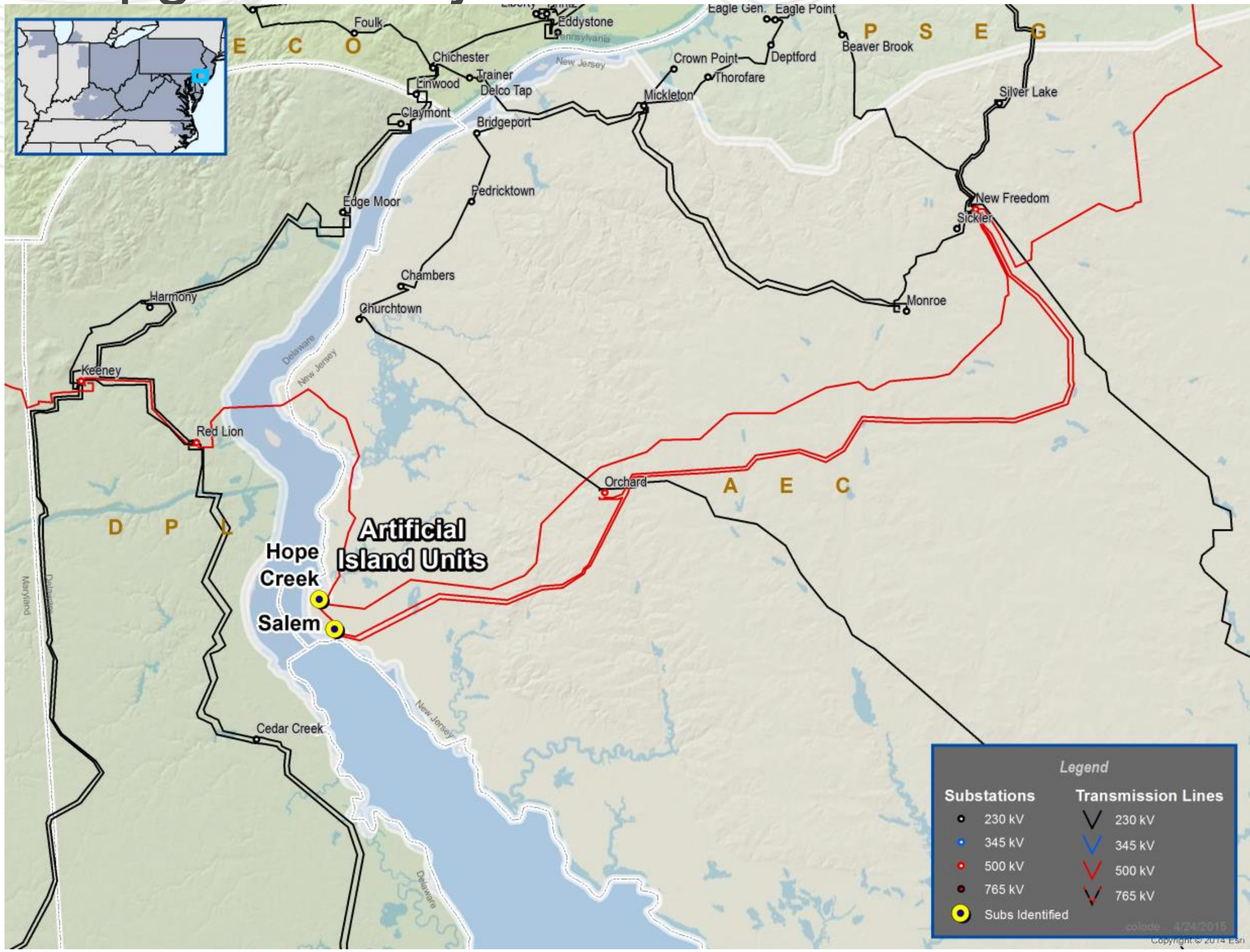
- Project cost estimate:
  - $25M
- Designate OPGW upgrades to PSE&G and PHI (5015 remote end)



Artificial Island Unit GSU Tap Settings
Upgrade Project Recommendation

- Implement changes to the tap settings for the three Artificial Island unit's step-up transformers(b2633.7)

- Designate GSU tap settings change upgrade to PSEG Power



Next Steps

- All stakeholder comments for the PJM Board must be sent no later than close of business on May 29

- If the PJM Board approves these recommendations, PJM staff will proceed to draft the Designated Entity Agreement

  – Recommendation is based upon PJM's understanding of the cost commitment terms and conditions, which will be finalized and incorporated into the Designated Entity Agreement

  – The first required milestone will be related to engineering feasibility of the river crossing utilizing horizontal directional drilling installation

Appendix

Supplemental Information Summary

Supplemental Information Request Timeline

- 08/12 – Letter sent to Proposing Entity ‘finalists’ to provide opportunity to supplement their proposals
- 09/12 – Supplemental information submitted to PJM by all ‘finalists’
- 09/18 – Redacted versions of the supplemental information is posted to PJM.com
- Oct 22 through Nov 3 – Meetings with FERC Administrative Law Judge and finalists to review and confirm information

LS Power Cost Containment Mechanism

- $146 Million
- Physical scope of work included under proposed mechanism
  - Aerial or submarine line
  - New substation located near the existing 230kV right-of-way in Delaware
- Physical scope of work not included under proposed mechanism
  - Salem substation modifications
    - New bay position
    - New 500/230kV transformer
  - 230kV turning poles cutting the two Delaware transmission lines

LS Power Cost Containment Mechanism

- Costs included under the containment mechanism
  - Permits and government approvals
  - Land acquisition
  - Environmental assessment and mitigation
  - Engineering
  - Equipment, supplies and other material procurement
  - All development and construction activities

LS Power Cost Containment Mechanism

- Costs not included under the containment mechanism
  - Financing costs
  - AFUDC
  - Additions and modifications to the project scope due to
    - “any material change in the enforcement, interpretation of application of any statue, rule, regulation, order or other applicable law existing..”
    - “any Breach or Default by PJM of its obligations under the DEA or any request by PJM to delay or suspend any activities associated with the Project”.
    - “any breach, default, interference or failure to cooperate by any Transmission Owner in connection with the Interconnection Coordination Agreement or interconnection agreement”

Transource Cost Containment Mechanism

- Proposed tiered cost containment mechanism
  - Up to $203 Million: entitled to recover all FERC approved ROE plus incentives
  - Portion from $243 to $299.8 million: forego 50% of any FERC approved ROE incentives
  - Above $299.8 million: forego 100% of any FERC approved ROE incentives

- Physical scope of work included under proposed mechanism
  - 230kV submarine cable from Salem substation to new substation in Delaware
  - New substation located near the existing 230kV right-of-way in Delaware
  - New 500/230kV substation adjacent to Salem substation

- Physical scope of work not included under proposed mechanism
  - Modifications in and near Salem substation
    - New bay position at Salem
  - 230kV turning poles cutting the two Delaware transmission lines

Transource Cost Containment Mechanism

- Transource provided a contingency amount of $52.3 million which is included in the second tier of their cost containment mechanism
  - Some specific contingency items identified (redacted)
  - General 10% project contingency

PSE&G Cost Containment Mechanism

- $221 Million

- Physical scope of work included under proposed mechanism
  - Aerial 500kV line from Hope Creek to Red Lion substations
  - Upgrade work at Hope Creek to create the new line bay

- Physical scope of work not included under proposed mechanism
  - Upgrade work at Red Lion to create the new line bay

PSE&G Cost Containment Mechanism

- Costs included under the containment mechanism
  - All project costs with exceptions as noted below

- Costs not included under the containment mechanism
  - Costs associated with PJM modifications or additions to the scope of work
  - Costs incurred from the following events deemed outside of the control of PSE&G:
    - Changes in applicable laws and regulations
    - Obtaining governmental approvals and permits
    - Obtaining necessary property rights to construct the Project
    - Environmental permitting, remediation and mitigation
    - Orders of courts or action or inaction by governmental agencies

Dominion Supplemental Information

- Dominion did not provide a cost containment mechanism, but rather provided reasons for confidence in their ability to meet cost estimates and elaborated on project management approach and past experience with transmission projects
  - Red Lion to Hope Creek: agreed with PJM's cost estimate of $242 to $292 million
  - FACTS based solution: provided a revised cost estimate of $174.1 million
    - $86.4 million based upon vendor not-to-exceed budget prices

Revision History

- V1 4/28/2015 – Original Presentation Posted
- V2 4/28/2015 – Slide 45 updated to reflect May 29th comment date
- V3 05/06/2015 – Slide 39 updated to reflect the July 27 PJM Board meeting

AI Complaint Appendix 6: May 8, 2014 TEAC Presentation

Transmission Expansion Advisory Committee

May 8, 2014

Interregional Planning Update

EIPC non-grant 2014 Analysis

- 2014 Scenario Analysis
  - Scenario A - Update rollup case
  - Scenario B - Severe Heat and Drought
  - May – July - target assumptions and model builds
  - July Stakeholder WebEx
  - June – August - target analysis
  - Sept – Oct - target draft report
  - November - target Stakeholder WebEx

Interregional Planning Studies (not including JCM)

- NCTPC
  - Study requested by NCUC
  - Reliability and Economic impact of BRA resources
  - Reliability Scope complete
  - Economic Scope under development
  - 2014 target completion
- PJM/MISO Joint Planning Study
  - Futures 1, 2, 3 analysis is complete
  - Stakeholder comments have been incorporated
  - Results under review
- Northeast Protocol Studies Update – NCSP posted

2014 RTEP Proposal Windows Update

2014 RTEP Proposal Windows Update

- 2014 RTEP Approach
  - 2019 Summer Baseline N-1 Thermal result
    - Posted to the 2014 RTEP proposal window participants www.pjm.com
  - 2019 Summer Generator Deliverability and Common Mode Outage result
    - Quality control check with TOs is in progress
    - To be distributed upon completion of quality control check
  - 2019 Summer Load Deliverability results
    - Analytical study in progress at PJM
  - 2019 Summer NERC Category C3 “N-1-1” result
    - To begin following load deliverability

Reliability Analysis Update

Dominion Transmission Zone

- **Operational Performance**

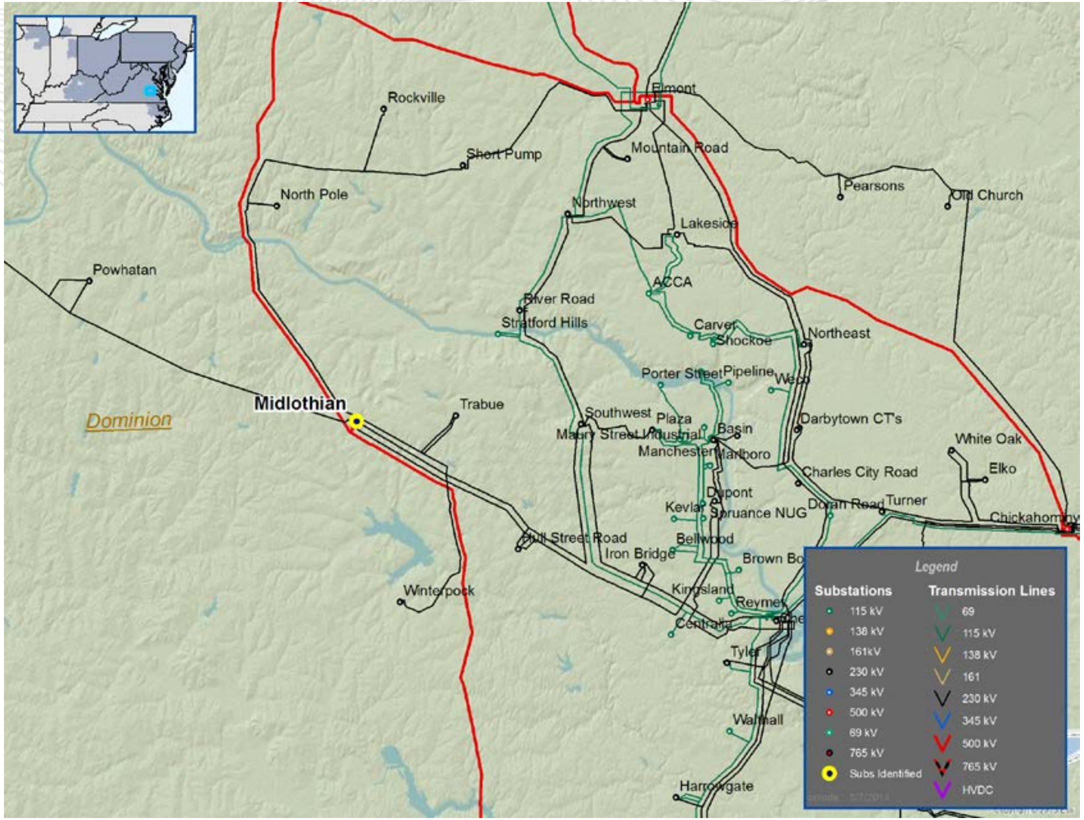
- **Midlothian 500kV Ring Bus**

- Midlothian is the last remaining substation on the Dominion system that has a 500/230kV transformer that is tapped directly to a 500kV line and has motor operated switches. This does not meet Dominion's minimum operating standards for 500kV.

- Proposed Solution: At Midlothian, replace 500kV breaker 563T576 and motor operated switches with a 3 breaker 500kV ring bus. Also, terminate Lines #563 Carson to Midlothian and #576 Midlothian to North Anna and Transformer #2 in the new ring.

- Projected IS Date: Nov 2015

- Estimated cost $ 9 M



Dominion Transmission Zone

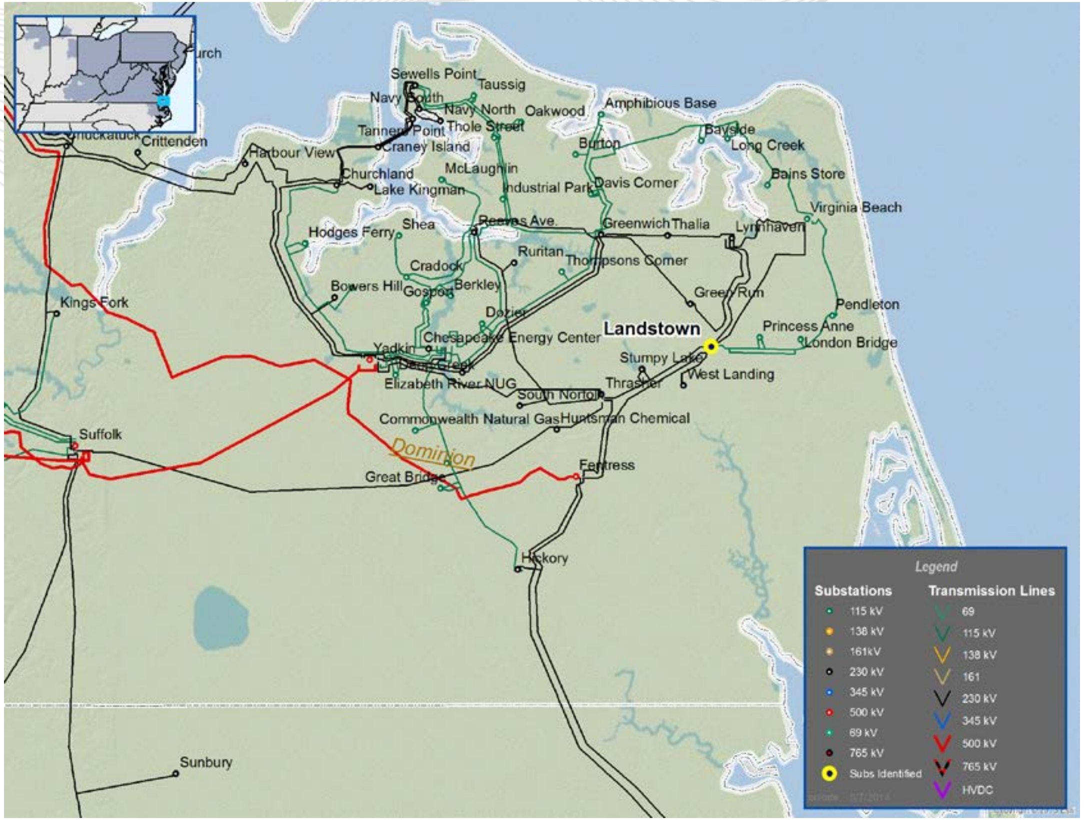
- **Baseline Project b1912 scope update**
  - Project B1912 was established due to the Chesapeake Units #1-4 Retirement
  - Re-consider scope due to electrical and physical considerations

- Existing Problem: Voltage collapse in the Va Beach area for an N-1-1 outage of Suffolk-Yadkin 500 kV Line and the Yadkin – Fentress 500 kV Line

- Previous Proposed Solution: (B1912) – Install a 500 MVAr SVC at Landstown.
  - Re-consider this solution due to electrical and physical considerations

- Previous Estimated Project Cost: $60 M.
- Projected IS Date: 06/01/2016

Continued on the next slide…..



Dominion Transmission Zone

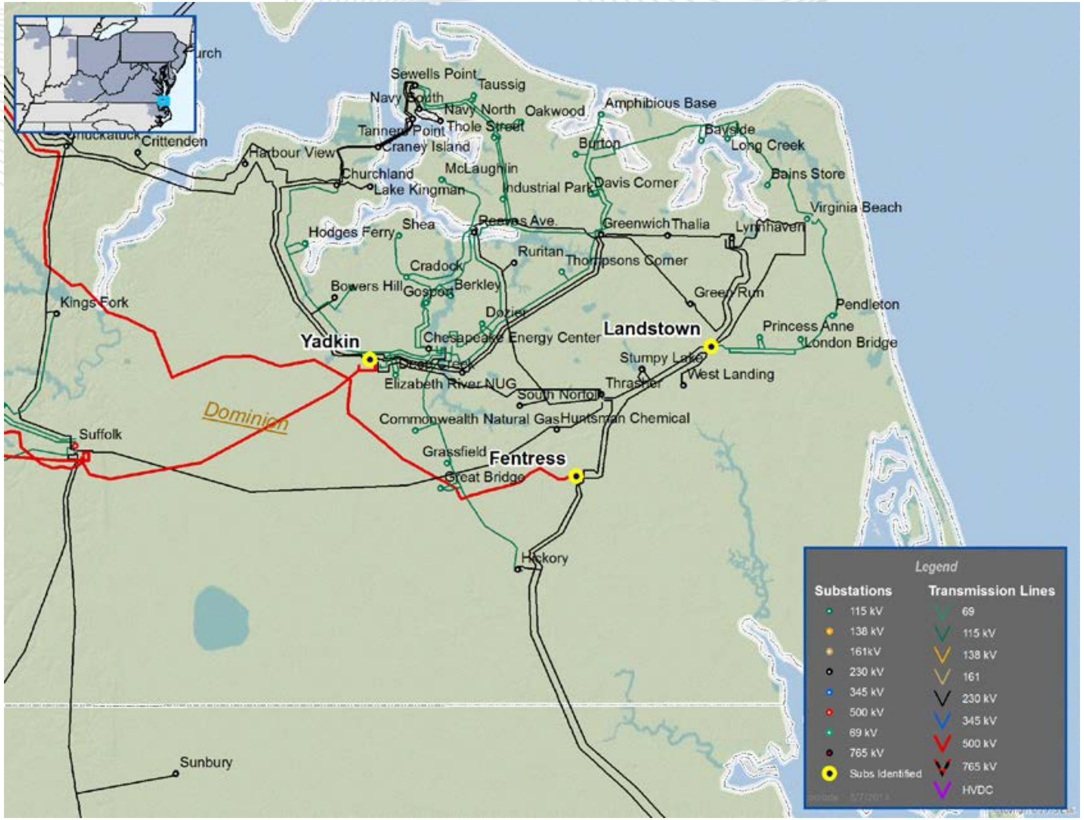
…continued from the previous slide

- **Chesapeake Units #1-4 Retirement - Revised Solution**
- **Existing solution:** Install a 500 MVAr SVC at Landstown.
- Estimated Project Cost: $67 M

- **New recommended solution:** Install three smaller +/- 125 MVAr STATCOM at three different Substations (Landstown, Yadkin, Fentress)
- New Estimated Project Cost $70 M

- New recommended solution benefits:
  - Three smaller distributed resources, instead of a single larger resource
  - Improved reliability in coastal environment due to the indoor configuration of a STATCOM
  - Less acoustic noise in urban areas
  - Three locations provide better physical security and a smaller foot print
  - Device response
  - Located closer to load centers

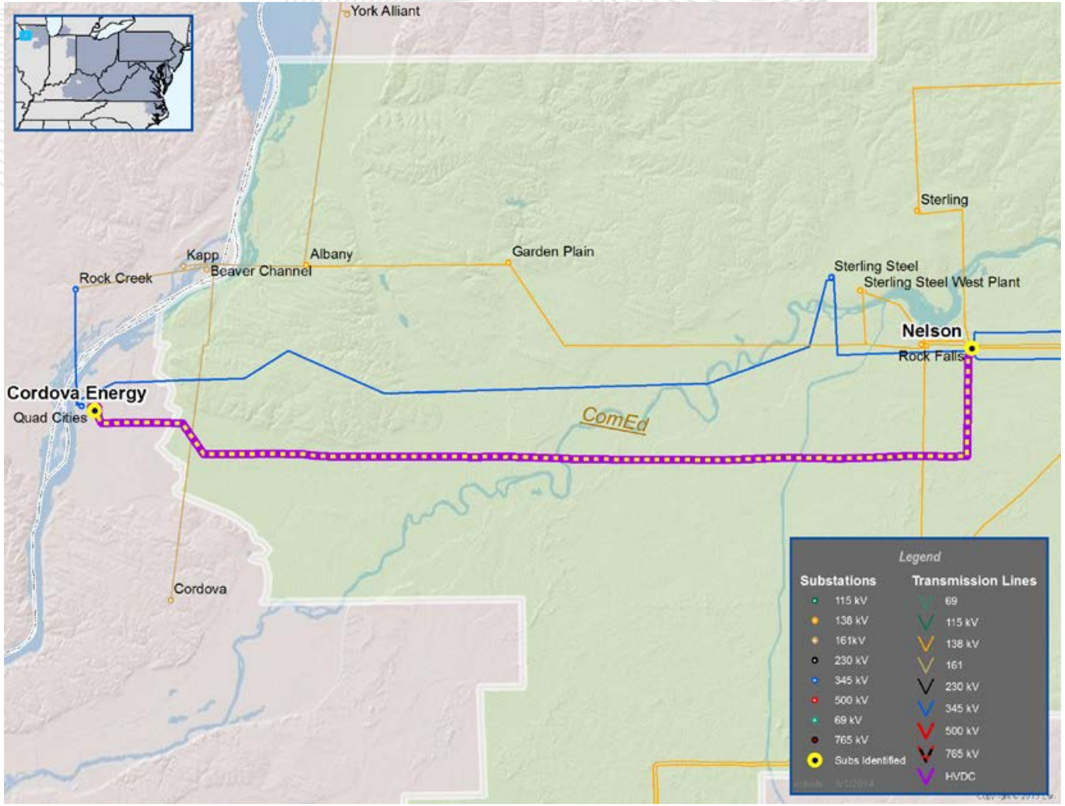
- Projected IS Date: 06/01/2016



Supplemental Projects

ComEd Transmission Zone

- **Supplemental Project**
- To improve reliability and operability in the ComEd Western zone by addressing constraints consistently observed in real-time and day-ahead studies.
- Reconductor 0.4 miles of 345 kV line 15503 from Cordova to Nelson and replace breaker leads at Nelson. (S0704)
- Estimated Project Cost: $1.0 M
- Projected IS Date: 6/1/2015



Winter Peak Study Update

2019 Winter Study Update

- PJM Winter Study Model
  - Topology - based on 2019 RTEP Summer Peak case
  - External model – 2019 MMWG winter model
  - Facility Ratings - winter thermal ratings
  - Forecast - PJM Winter load forecast
  - Demand - Winter load profile submitted by TOs
  - Dispatch
  - Area interchange is the net PJM Long Term Firm commitments
- In progress
  - Examination of pumped hydro modeling during winter peak
  - Continue to examine winter generation outage rates
  - Capacity Factor calculation from a 2019 market efficiency study

- Winter Peak Hours Capacity Factors

FUEL TYPE	Solar	Coal (<500MW)	Landfill Gas	Natural Gas	Nuclear	WAT Run of River	Wind	Coal (>500MW)
AVG CF (2008-2013)	0.05	0.51	0.46	0.25	0.98	0.38	0.33	0.73

- Capacity Factor Comparison between Summer and Winter (all hours)

Fuel Type	Solar	Coal (<500MW)	Landfill Gas	Natural Gas	Nuclear	WAT Run of River	Wind
SUMMER CF	0.2	0.52	0.52	0.13	0.94	0.33	0.16
Winter CF	0.09	0.63	0.46	0.22	0.98	0.1	0.34

- Capacity Factor Next Steps
  - Evaluate the capacity factor data to determine appropriate base case and ramping values for generation by fuel type

2019 Winter Study Update

- Changes might impact capacity factors in the next several years
  - Significant coal generation retirement
  - Gas price change
- ProMOD Study to predict the future CF for different type of generators
- Analytical studies to perform
  - Contingencies
- Potential next steps
  - Deliverability test similar to light load test with different ramping level using the uniform dispatched case
    - Ramping of hydro
    - Ramping of wind
    - Similar to other deliverability tests, the ramping limit for the remaining generators will be 100%
  - Sensitivity to change of the generator dispatch in base case

2019 Winter Study Update

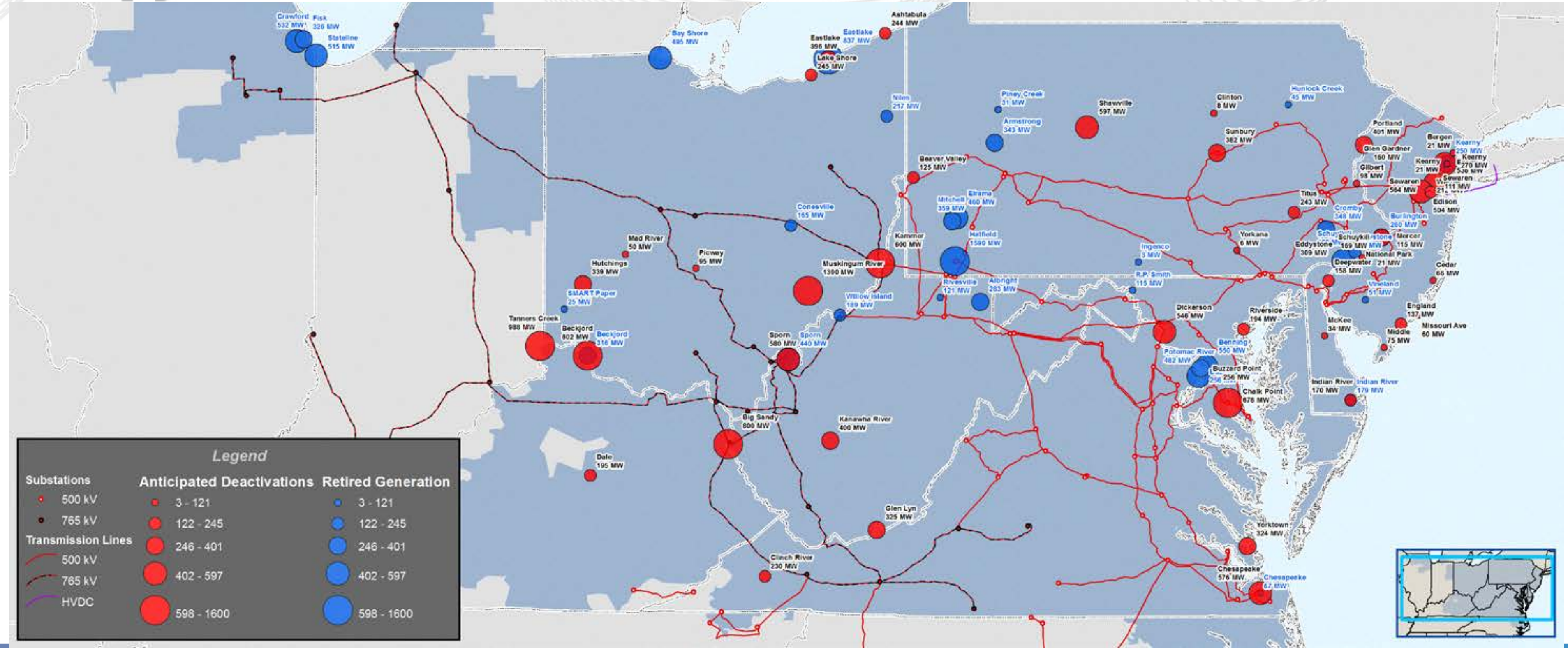
- Next Steps
  - ProMOD Study to predict the future CF is targeted to be done in June
  - The initial deliverability test will start in June

Generation Deactivation Notification Update

Deactivation Status

Unit(s)	Transmission Zone	Requested Deactivation Date	PJM Reliability Status
Dale Units 1-4 (193MWs total)	EKPC	4/16/2015	Reliability analysis complete. No impacts identified.
- UPDATED Sunbury 1-4 (382MWs total)	PPL	7/18/2014 (Previous 6/1/2015)	Reliability analysis underway
- UPDATED Riverside 4 (76MWs)	BGE	6/1/2015 (Previous 6/1/2016)	Reliability analysis underway
-UPDATED Chalk 1, 2 & Dickerson 1-3 (1224MWs)	PEPCO	5/31/2018 (Previous 5/31/2017)	Reliability analysis underway

Generation Retirements

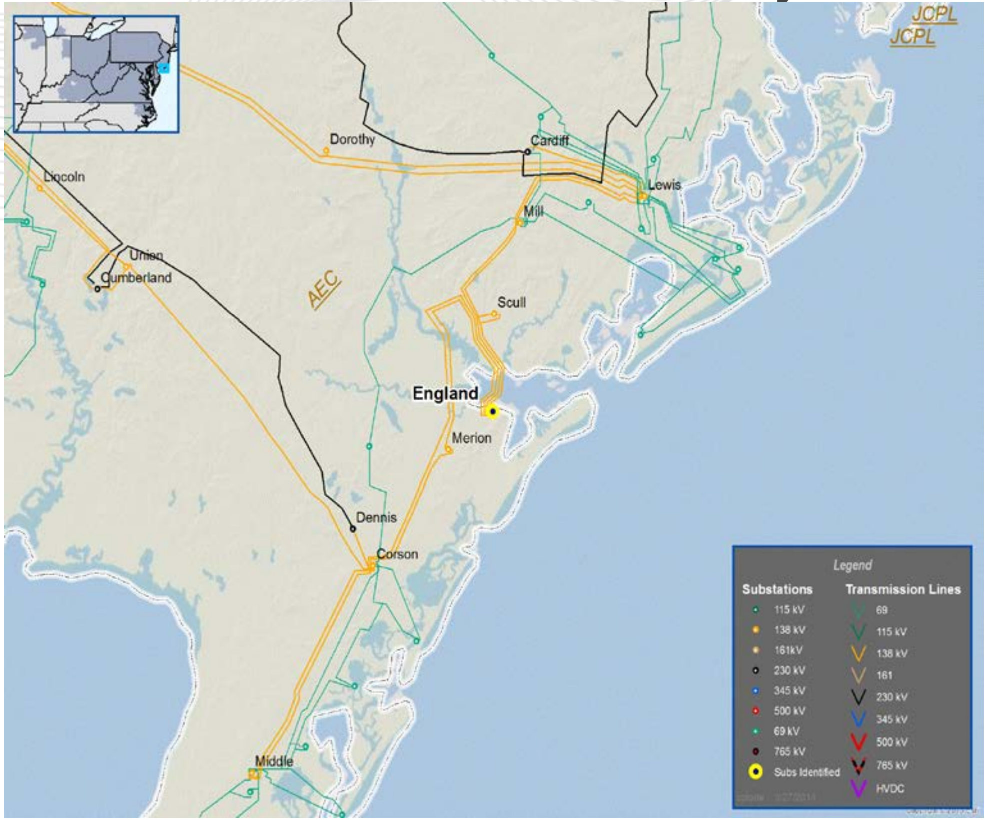


At-Risk Generation Analysis

Deactivation At Risk Analysis

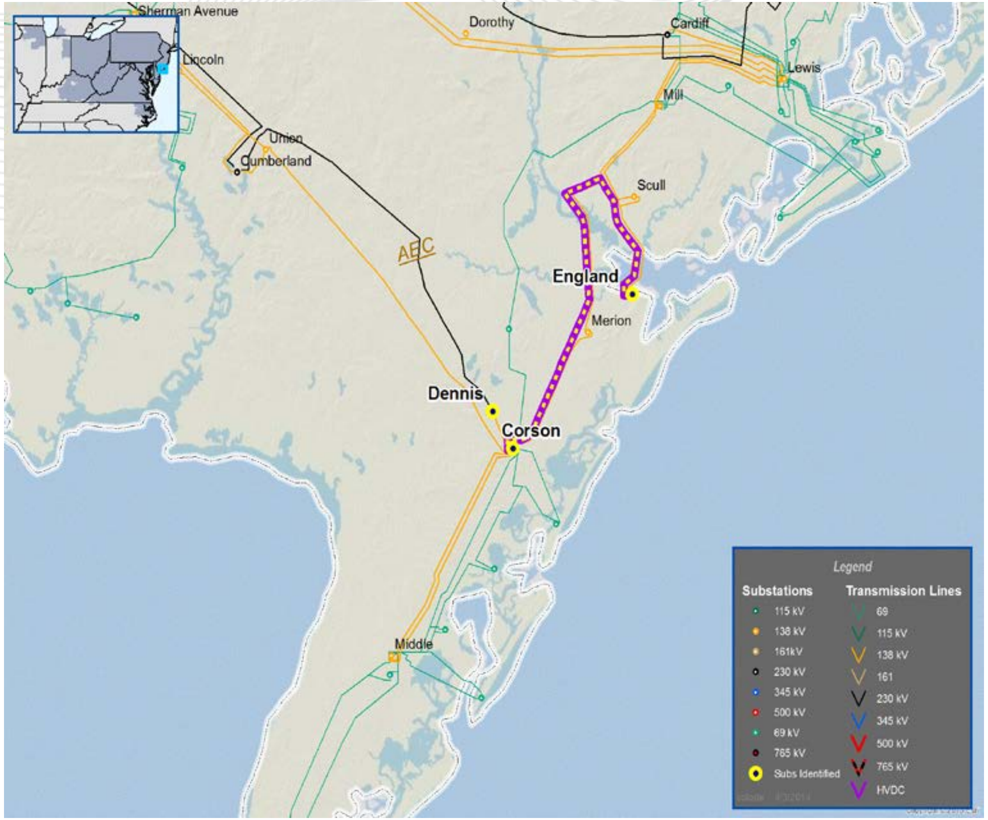
- BL England diesel: 8 MW
- BL England unit 2: 155MW
- BL England unit 3: 148.9MW
  - ACE Transmission Zone
  - 288 MW Total
  - Deactivation date: 06/01/2015

- BL England unit1 was modeled offline in this study as it was already studied for deactivation



ACE Transmission Zone

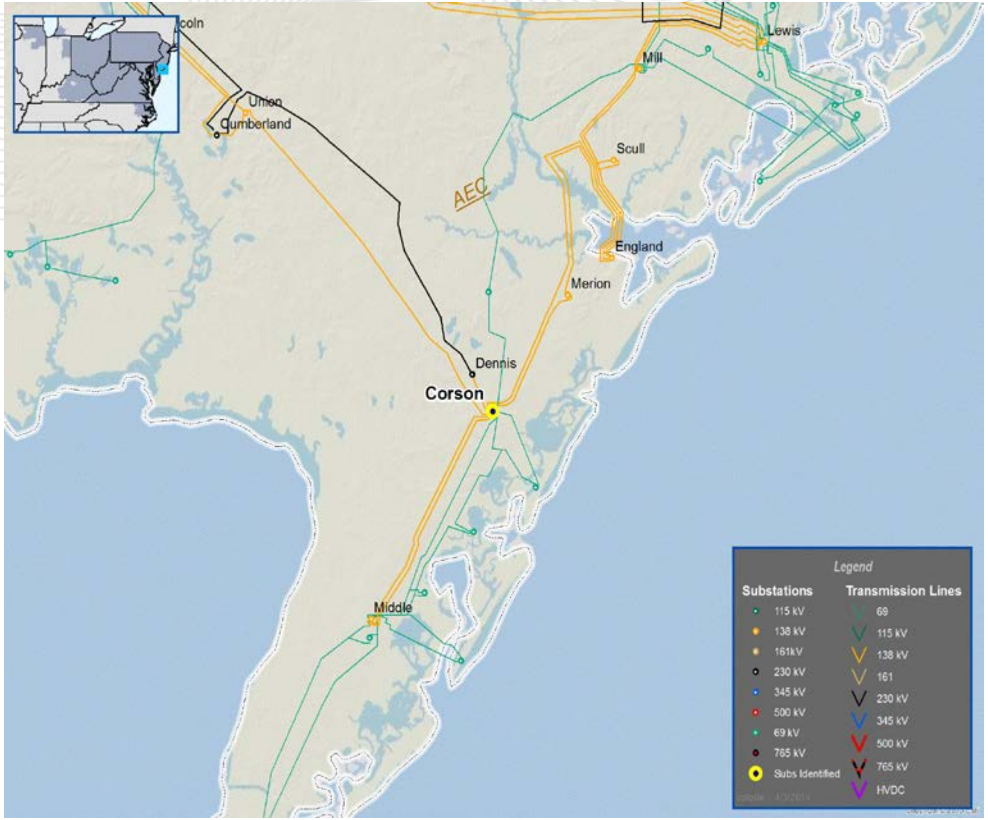
- N-1-1 Violation
- The DENNIS 230/138kV transformer is overloaded to 119.35% and DENNIS – CORSON 2 138kV line is overloaded to 114.37% for the loss of the New Freedom to Cardiff 230 kV line (CONTINGENCY 'NEWFDM-CARD') followed by the loss of Corson 3 – Union 138kV line (CONTINGENCY 'CORSON-UNION')
- *The MDLE TP – BLE 138kV line is overloaded to 102.81% for the loss of New Freedom – Cardiff 230 kV line followed by the loss of Oyster Creek – Cedar 230 kV line*
- Install new Dennis 230/69kV transformer
- Cost Estimate: $15.2M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/01/2016



ACE Transmission Zone

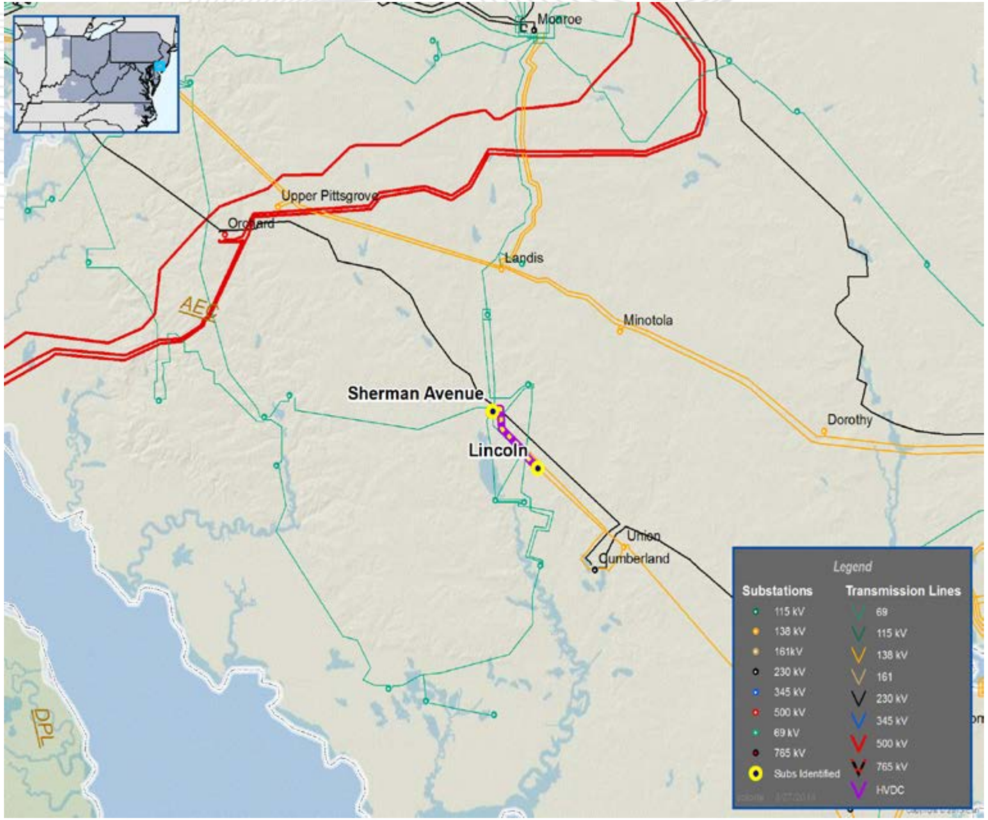
At Risk – BL England Units 2,3, and diesel

- N-1-1 Violation
- The CORSON 2 - CORSON 1 138kV line is overloaded to 115.97% for the loss of the New Freedom to Cardiff 230 kV line (*CONTINGENCY 'NEWFDM-CARD'*) followed by the loss of Corson 2 – MDLE TP kV 138kV line (*'228107(CORSON 2)-228111(MDLE TP)_1'*)
- The CORSON 2 - MDLE TP 138kV line is overloaded to 114.31% *for the loss of New Freedom – Cardiff 230 kV line followed by the loss of Corson 1 – Corson 2 138kV line* (*CONTINGENCY '228106(CORSON 1)-228107(CORSON 2)_1'*)
- Upgrade 138kV and 69kV breakers at Corson substation
- Cost Estimate: $0.8M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/01/2016



ACE Transmission Zone

- N-1-1 Violation
- The SHRMAN#3 - LINCOLN 138kV line is overloaded to 103.22% for the loss of the Dennis – Corson 2 138kV (*CONTINGENCY 'DENN-COR')* followed by the loss of Union – Cumberland 138kV line (*CONTINGENCY '228210(UNION)-228262(CUMB)_1')*
- Reconductor 2.74 miles Sherman-Lincoln 138 kV line
- Sherman substation work
  - Cost Estimate: $0.11M
- Lincoln substation work
  - Cost Estimate: $0.11M
- Cost Estimate: $4.0M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/01/2016



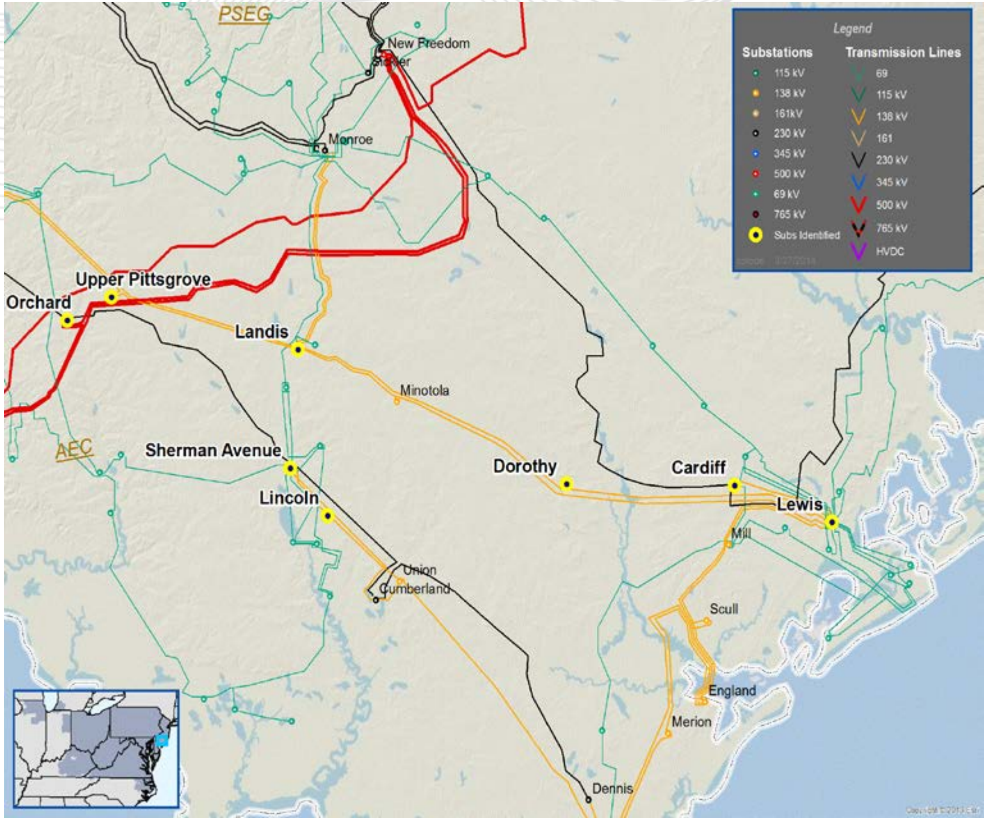
At Risk – BL England Units 2,3, and diesel

ACE Transmission Zone

Multiple N-1-1 Thermal and N-1-1 Voltage magnitude and drop violations in ACE area are addressed by this set of upgrades

- IS Date 6/1/2015
- Expected IS Date: 6/01/2017-06/01/2018
- New Orchard – Cardiff 230kV line (Remove, rebuild and reconfigure existing 138 kV)
  - Cost Estimate: $57.0M
- New Upper Pittsgrove – Lewis 138kV line
  - Cost Estimate: $28.0M
- New Cardiff – Lewis #2 138kV line
  - Cost Estimate: $3.5M
- Orchard substation work to accommodate new Orchard – Cardiff 230kV line
  - Cost Estimate: $3.6M
- Upper Pittsgrove substation work
  - Cost Estimate: $0.05M

Continues on the next slide…



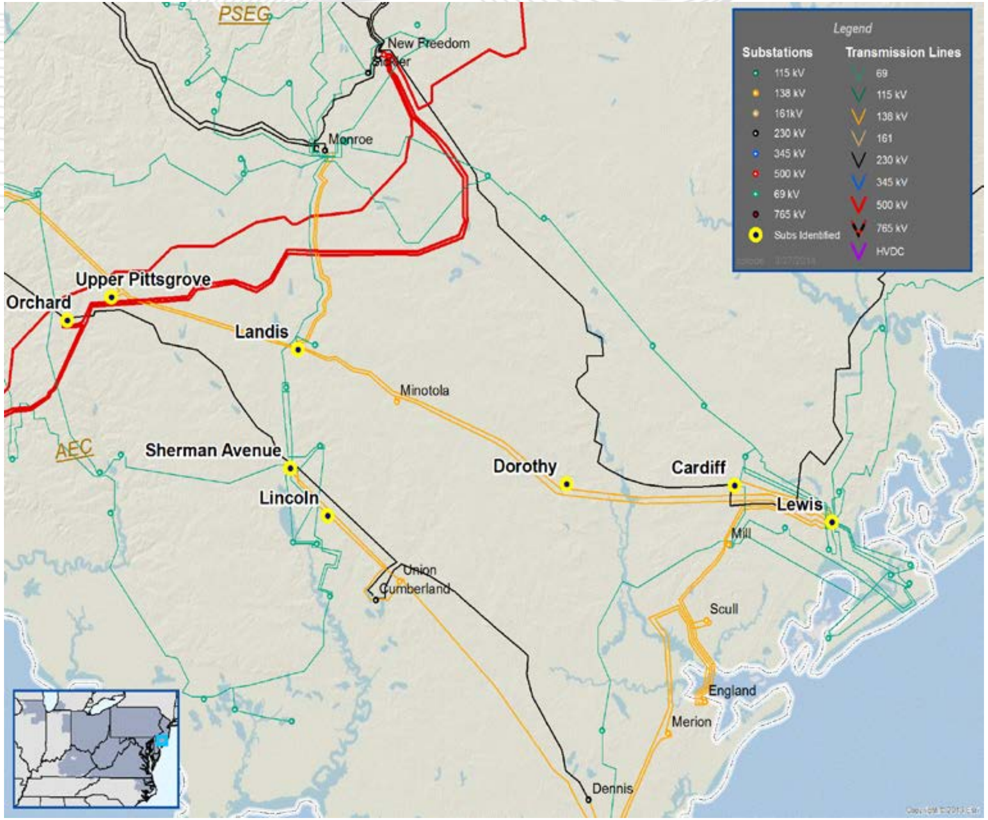
At Risk – BL England Units 2,3, and diesel

ACE Transmission Zone

Continued from the previous slide:

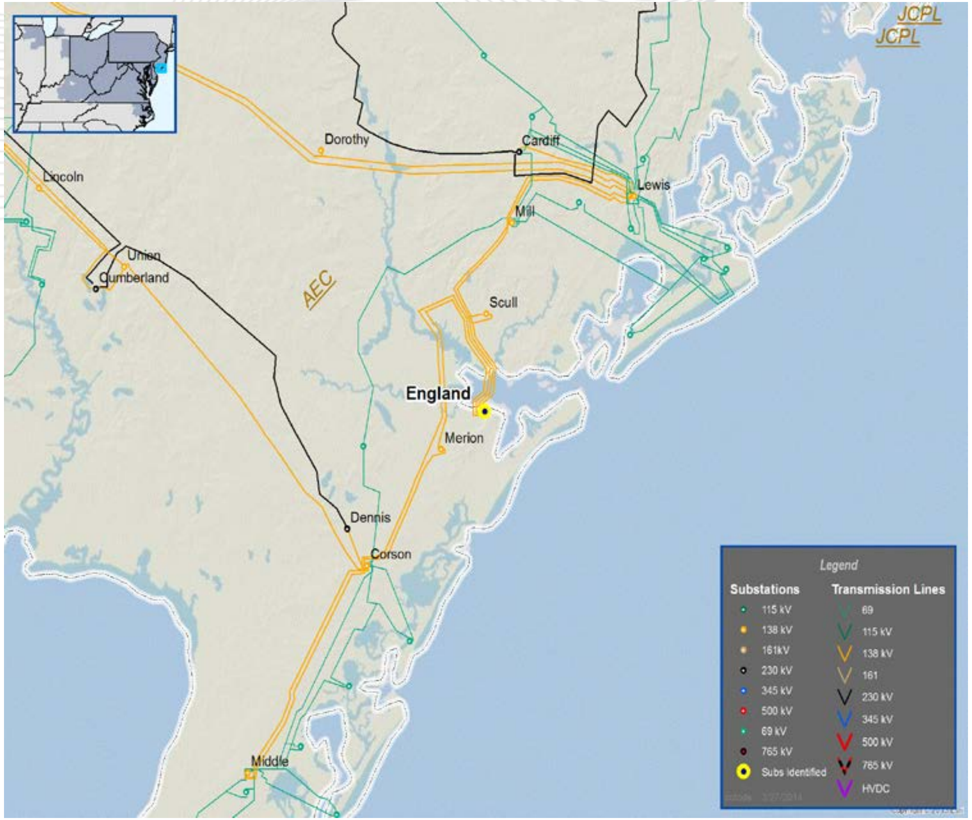
- Landis substation work to convert Landis to a ring bus and connect 3 lines to it
  - Cost Estimate: $13.4M
- Dorothy substation work – replace two switches with breakers
  - Cost Estimate: $4.0M
- Cardiff substation work to accommodate new Orchard – Cardiff 230kV line and new Cardiff – Lewis 138kV line
  - Cost Estimate: $16.4M
- Lewis substation work
  - Cost Estimate: $0.1M
- Environmental
  - Cost Estimate: $2M

Note: These upgrades will use existing ROW and will also address significant existing age and condition issue of 40 mile 138 kV double circuit tower line.



ACE Transmission Zone

- Short term solution to multiple N-1-1 Voltage Violation in ACE area is to install a 100 MVAr capacitor at BLE
- Cost Estimate: $4.0M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/1/2016

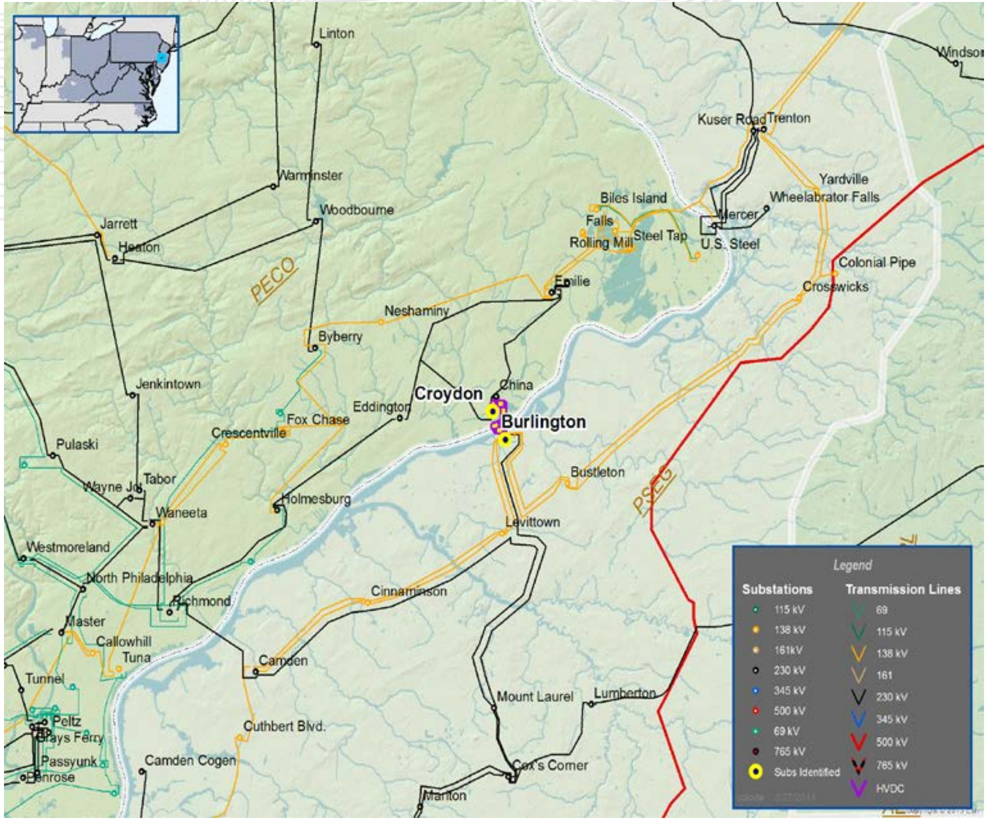


At Risk – BL England Units 2,3, and diesel

PECO Transmission Zone

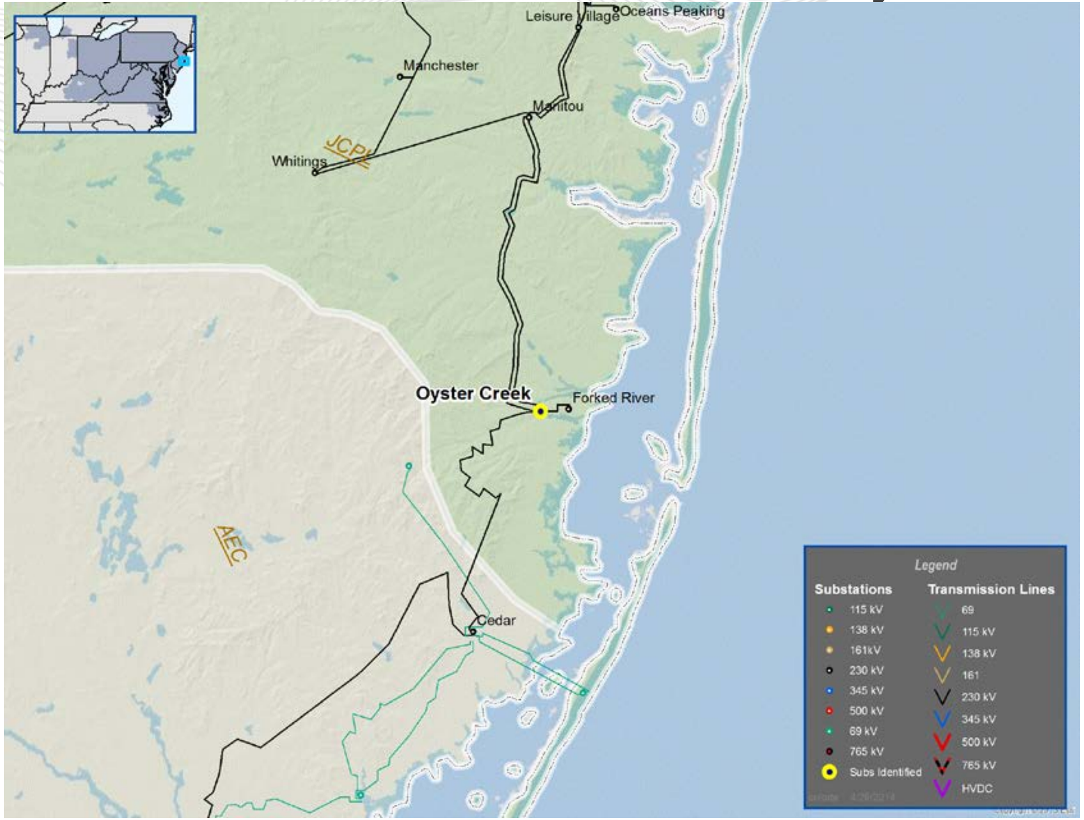
- **Generator Deliverability Violation**
- Croydon – Burlington 230kV line is overloaded to 107.61%% for the loss of Neshaminy 138kV bus (*CONTINGENCY '130-25/* $ BUCKS $ 130-25 $ L'*)
- *Existing baseline upgrades b1197 and b1197.1 – reconductor Croydon – Burlington 230kV line*

- Cost Estimate: $8.6M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/1/2015



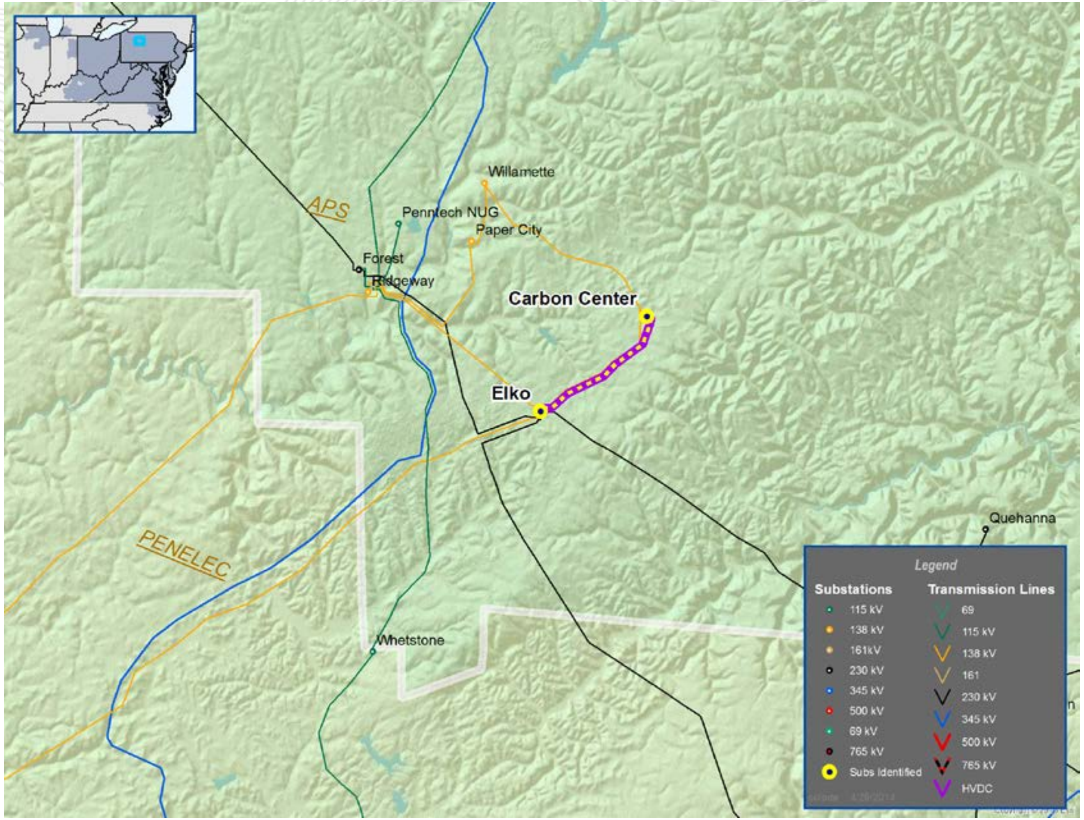
Deactivation At Risk Analysis

- Study Assumptions
  - Oyster Creek Nuclear unit: 614.5 MW
    - Deactivation date: 06/01/2017
  - BL England Units deactivated
  - Upgrades noted on the previous slides in-service
- Results – No new problems in southern NJ
- Following slides include potential issues and solutions outside southern NJ for this scenario



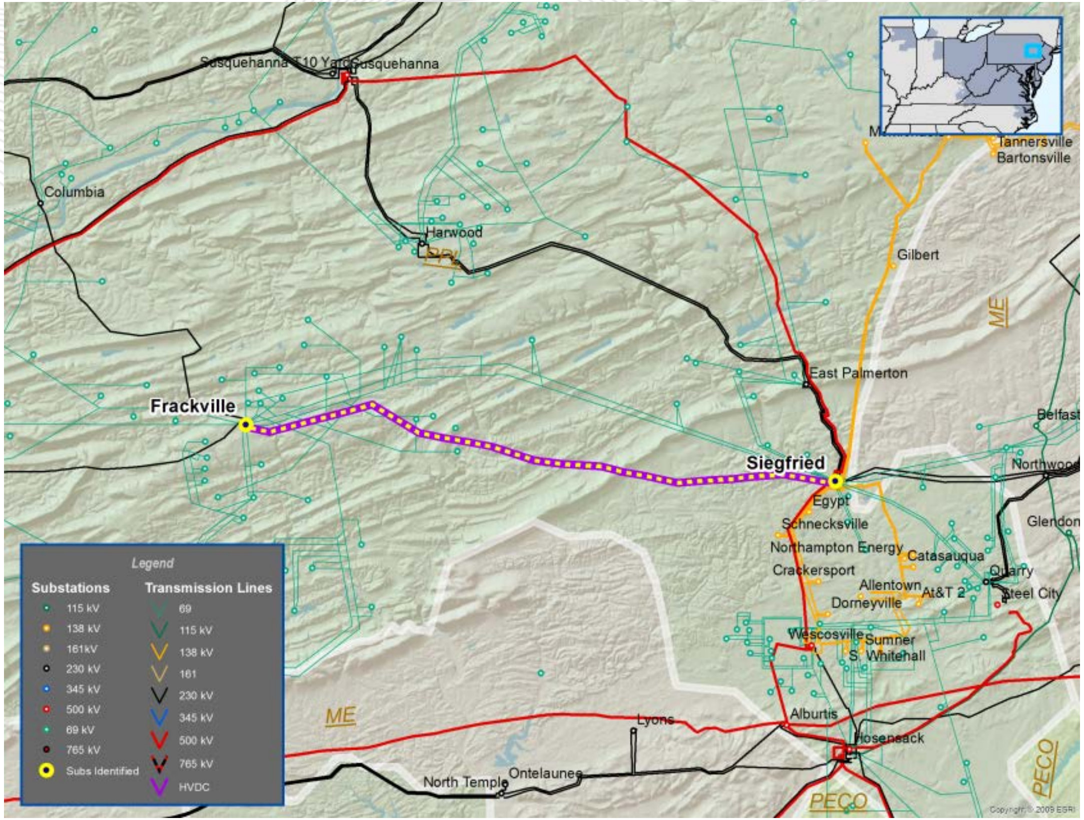
APS Transmission Zone

- N-1 Common Mode violation
- Elko to Carbon Center Junction 138 kV line is overloaded to 115.95% of its emergency rating (132 MVA) for the outage of Elko to Squab Hollow 230 kV line and Elko 230/138 kV transformer for the stuck breaker failure at Elko 230kV TR#1 (‘AP_SB_442’).
- New Upgrade: Reconductor 138 kV bus at Elko. New Rating: 160 MVA (SN) 192 MVA (SE)
- Cost Estimate: $150,000
- Required IS Date: 6/1/2017



PPL Transmission Zone

- Generation Deliverability Violation
- Frackville to Siegfried 230 kV line is overloaded to 106.42% of its emergency rating (628.63 MVA) for the outage of Sunbury 500/230 kV transformer#24, Sunbury unit 4 for the stuck breaker at Sunbury 230 kV 5S (‘PL101002’).
- Existing Upgrade: b2282 - Rebuild the Siegfried-Frackville 230 kV line
- Cost Estimate: $84.5 M
- Required IS Date:
  6/1/2018

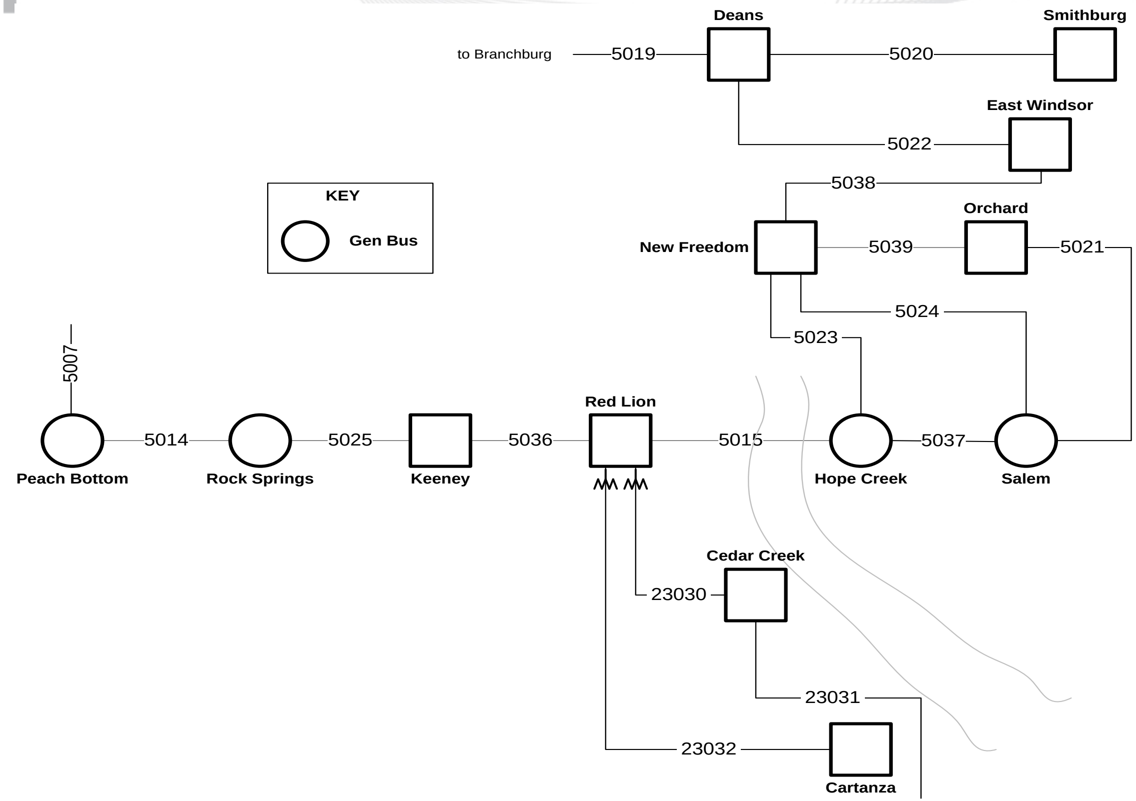


Next Steps

- Study of other generation which may be at risk for deactivation due to economics, environmental regulations, etc.

Artificial Island Update

Artificial Island Area Network



Artificial Island Proposals - Overview

- 26 proposed solutions
- Approximate cost range of $100 M to $1,550 M
- Technology includes transmission at both 500 kV and 230 kV, new transformation, substations and associated equipment, additional circuit breakers, system reconfiguration, dynamic reactive, dynamic series compensation
- Diversity of project risk, requirements and timelines

Project ID	TO	Cost ($)	Major Components	Supporting info
P2013_1-1A	Virginia Electric and Power Com	$ 133	500 MVAR SVC near New Freedom	Two (2) Thyristor Controlled Series Compensation (TCSC) Devices near New Freedom
P2013_1-1B	Virginia Electric and Power Com	$ 126	New 500 kV from Salem - a new station in Delaware	New 500/230 kV station in Delaware that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-1C	Virginia Electric and Power Com	$ 202	New 500 kV from Hope Creek - a new Station in Delaware	Install a new 500kV line from Hope Creek - Red Lion; New Salem - Hope Creek 500 kV line
P2013_1-2A	Transource	$213 - $269	Salem - Cedar Creek 230 kV	Two (2) 500/230 Transformers near Salem; Loop in Red Lion - Cartanza 230 to Cedar Creek
P2013_1-2B	Transource	$165 - $208	Salem - North Cedar Creek (new) 230 kV	Two (2) 500/230 transformers near Salem and loop in Red Lion - Cartanza 230 and Red Lion - Cedar Creek 230 kV
P2013_1-2C	Transource	$123 - $156	Salem - Red Lion 500 kV	
P2013_1-2D	Transource	$788 - $994	New Freedom - Lumberton - North Smithburg (New) 500 kV line	New Salem - Hope Creek 500 kV line and new 500/230 station east of Lumberton
P2013_1-3A	First Energy	$410.7 (Only FirstEnergy portion)	New Freedom-Smithburg 500 kV line with a loop into Larrabee	Hope Creek - Red Lion 500 kV line
P2013_1-4A	PHI Exelon	$ 475	Peach Bottom - Keeney - Red Lion - Salem 500 kV	Remove Keeney - Red Lion 230 kV; Reconfigure 230 around Hay Road; Reconductor Harmony-Chapel St 138 kV
P2013_1-5A	LS Power	$116.3M - $148.3M	Salem - Silver Run (new) 230 kV; Salem 500/230 kV Transformer	New 230 kV station that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-5B	LS Power	$ 170	Salem - Red Lion 500 kV	
P2013_1-6A	Atlantic Wind	$ 1,012	320 kV HVDC Salem/Hope Creek - Cardiff	SVC at Salem/Hope Creek; New HVDC Stations at Cardiff and Salem
P2013_1-7A	PSE&G	$ 1,371	Salem-Hope Creek to Peach Bottom 500 kV	Existing ROW
P2013_1-7B	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with Loop into Keeney
P2013_1-7C	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same at 7A with Loop into Red Lion
P2013_1-7D	PSE&G	$ 831	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with New ROW
P2013_1-7E	PSE&G	$ 692	New Freedom - Deans 500 & Salem - Hope Creek 500 kV lines	
P2013_1-7F	PSE&G	$ 879	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Existing ROW
P2013_1-7G	PSE&G	$ 1,034	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Same as 7F with a Loop into a new Larrabee 500 kV station
P2013_1-7H	PSE&G	$ 1,177	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Northern Route
P2013_1-7I	PSE&G	$ 1,353	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Same as 7H with the Southern Route
P2013_1-7J	PSE&G	$ 915	New Freedom - New Station on Branchburg-Elroy 500 kV line ("5017 Junction") and Salem - Hope Creek 500 kV line	Existing ROW
P2013_1-7K	PSE&G	$ 1,066	New Freedom - Deans & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7E with Hope Creek - Red Lion
P2013_1-7L	PSE&G	$ 1,250	New Freedom - Smithburg & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7F with Hope Creek - Red Lion
P2013_1-7M	PSE&G	$ 1,548	New Freedom - Whitpain (North) & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7H with Hope Creek - Red Lion
P2013_1-7N	PSE&G	$ 1,289	New Freedom - a new Station on the Branchburg-Elroy 500 kV line ("5017 Junction") & Salem-Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	

Artificial Island Preliminary Cost Allocation Examples

- Example allocation for project proposal P2013_1-4A
- P2013_1-4A
  - Build a new Peach Bottom - Keeney - Red Lion - Salem 500 kV
- See Schedule 12 of the PJM Tariff for the cost allocation method
  - http://pjm.com/~/media/documents/agreements/tariff.ashx

Transmission Zone	Load Ratio Share Allocation Portion	"DFAX" Allocation Portion	Resulting Combined Allocation
AEC	1.70%	38.08%	19.89%
AEP	14.18%	0%	7.09%
APS	5.39%	0%	2.70%
ATSI	8.16%	0%	4.08%
BGE	4.24%	0%	2.12%
ComEd	13.82%	0%	6.91%
ConEd	0.56%	0%	0.28%
Dayton	2.12%	0%	1.06%
DEOK	3.19%	0%	1.60%
DL	1.83%	0%	0.92%
Dominion	11.65%	0%	5.83%
DPL	2.49%	4.46%	3.48%
ECP**	0.20%	0.12%	0.16%
EKPC	1.57%	0%	0.79%
HTP***	0.01%	1.21%	0.61%
JCPL	3.96%	50.73%	27.35%
ME	1.87%	0%	0.94%
NEPTUNE*	0.42%	5.40%	2.91%
PECO	5.35%	0%	2.68%
PENELEC	1.92%	0%	0.96%
PEPCO	4.05%	0%	2.03%
PPL	4.59%	0%	2.30%
PSEG	6.46%	0%	3.23%
RECO	0.27%	0%	0.14%

*Neptune Regional Transmission System, LLC
**East Coast Power, LLC
***Hudson Transmission Partners, LLC

Artificial Island Conceptual Cost Allocation Examples

- Example allocation for project proposal P2013_1-5A
- P2013_1-5A
  - P2013_1-5A
  - Salem - Silver Run (new station) 230 kV
  - Salem 500/230 kV Transformer
  - New 230 kV Silver Run station that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV

Transmission Zone	Allocation
DPL	100.00%

Artificial Island Conceptual Market Efficiency Examples

- Market Efficiency Analysis Sensitivity Study
- Two scenarios
  - Scenario #1 – New 500 kV path from the AI to Red Lion
    - Result: Approximate benefit to cost ratio of 0.15
  - Scenario #2 – New path from the AI to Delaware (on the Cedar Creek - Catanza / Red Lion – Catanza path)
    - Result: Approximate benefit to cost ratio of 0.25

Artificial Island Technical Summary

		Southern Crossing Lines (Submarine)			Southern Crossing Lines (Overhead)		Red Lion to Artificial Island Lines				
							From Salem			From Hope Creek	
		LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - Overhead	Dominion 1B - 500kV Overhead	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek
Technical Analysis Criteria	**Stability**	Maximum angle swing range of 80 - 112 degrees, dependant on solution and SVC location			Maximum angle swing range of 80 - 110 degrees, dependent on solution and SVC location		Maximum angle swing range of 77 - 102 degrees, dependant on solution and SVC location				
	Thermal	Preliminary analysis indicates no thermal overloads			Preliminary analysis indicates no thermal overloads		Preliminary analysis indicates no thermal overloads				
	Market Efficiency Results	Approximate $92 M cost savings over 15 Years			Approximate $92 M cost savings over 15 Years		Approximate $57 M cost savings over 15 Years				
	Short Circuit	Three overdutied 500 kV breakers		No overdutied breakers	Three overdutied 500 kV breakers		No overdutied breakers				

- Additional stability analysis
  - Evaluating the scenario of Hope Creek – Red Lion 500 kV without a second tie between Hope Creek – Salem plus an SVC
  - Stakeholder suggestion that a Salem – Peach Bottom 500 kV line without an SVC would satisfy the Artificial Island problem statement
    - PJM analysis indicates that this configuration does not meet applicable stability testing criteria without an SVC

TEAC Notification for special TEAC Artificial Island Meetings on 5/19 & 6/16

Project Class			Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)		Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines	
Criteria		Proposal / Sub-Criteria	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek
Technical Analysis		Stability										
		Thermal										
		Market Efficiency Results										
		Short Circuit										
		Route Diversity										
		NERC Cat-D Contingencies										
Cost Factors		PJM Estimated Project Cost										
		Market Efficiency										
		Outage Costs										
Project Schedule		Permitting										
		Property Acquisition										
		Construction										
		Long Lead Time Materials										
		Outages										
Risk Factors to Cost and Schedule	Project Complexity	Line Crossings										
		Outage Requirements										
		Modification of Red Lion Sub										
		Modification of other Transmission Facilities										
		Modification of AI Subs										
	RoW and Land Acquisition	No Eminent Domain in Delaware										
		New Right of Way Required										
		Substation Land Required										
	Siting and Permitting	Wetlands Impact										
		Public Opposition Risk										
		Historic and Scenic Highway										
		Delaware River Crossing										
Operational Impact		Impact to Artificial Island Facility										
		Blackstart										
		Operational Performance										

May 19th Special TEAC Artificial Island Meeting

- Artificial Island Technical Review
- 09:00 – 12:00 at the PJM CTC and WebEx/Teleconference
- PJM Review of analytical and constructability progress
- Stakeholder Q&A

Artificial Island Timeline

- **Monday, May 19th Special TEAC**
  - **3 hour stakeholder technical meeting**
  - **In-person at PJM CTC**
- Monday, June 2nd – Due date for stakeholder comment/feedback (14 day comment period)
- June 5th TEAC
- **Monday, June 16th – PJM review of stakeholder comment/feedback and final decision meeting**
  - **Webex / Teleconference**
- Comment Period to the PJM Board (36 days for comment period)
- July 10th TEAC
- **Tuesday, July 22nd – PJM Board meeting**
  - **Artificial Island solution recommendation to the PJM Board**

Questions?

Email: RTEP@pjm.com

Revision History

- Version 1 – 5/6/2014 – Original Version Distributed to PJM TEAC
- Version 2 – 5/6/2014 – Updated slide #43 – AI evaluation categories
- Version 3 – 5/7/2014 – Updated slide #6 to 2019 study year & updated slides 39 and 40 regarding Market Efficiency
  – Added slides 8-10 for the Dominion Transmission Zone to the Reliability Analysis Update section
  – Updated Slide 31 contingency and costs
- Version 4 – 5/9/2014 – Updated with feedback received at the 5/8/2014 TEAC meeting

AI Complaint Appendix 7: Affidavit of John M. Marczewski

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Delaware Public Service Commission, and Maryland Public Service Commission Complainants, v. PJM Interconnection, L.L.C., and Certain Transmission Owners Designated Under Attachment A to the Consolidated Transmission Owners Agreement, Rate Schedule FERC No. 42 Respondents.	)))))))))))))	Docket No. EL15-_____-000

AFFIDAVIT OF JOHN J. MARCZEWSKI

I, John J. Marczewski, being first duly sworn, do depose and say:

<u>Background</u>

1. My name is John J. Marczewski. I am a Principal in the Energy Initiatives Group, LLC ("EIG"), located at 29 Bartlett Street, Marlborough, MA 01752.

2. I have worked in the electric utility industry for over twenty-eight years and am familiar with electric transmission planning, operations, design, equipment and construction. I earned a Bachelor of Science degree in Electrical Engineering from Worcester Polytechnic Institute in 1985 and a Master of Engineering degree in Electric Power Engineering from Rensselaer Polytechnic Institute in 1988. My electric industry experience began at the Massachusetts Electric Company in 1985 where I worked as an associate field engineer. After I left the Massachusetts Electric Company in 1987, I

attended graduate school at Rensselaer Polytechnic Institute and then returned to work as an engineer for the New England Power Service Company. In 1992, I transitioned to PLM, Inc., where I was a principal engineer responsible for transmission and distribution substation design and project management. In 1999, I began working as an independent consultant and founded EIG in 2000. Much of my work as a consultant has involved developing and managing interconnections and related studies with host utilities, analyzing and developing merchant transmission projects, and evaluating new transmission technologies and equipment. I have been involved in projects interconnecting and operating in PJM since 2002. My curriculum vitae is attached as Exhibit 1 to this Affidavit.

3. This Affidavit is being provided in support of the Complaint of the Delaware Public Service Commission ("DE PSC") and the Maryland Public Service Commission ("MD PSC") against PJM Interconnection, L.L.C. ("PJM") and certain PJM Transmission Owners in the above-captioned proceeding regarding PJM's proposed allocation of costs for the Artificial Island Project, which has been selected to be included in PJM's Regional Transmission Expansion Plan ("RTEP"). Capitalized terms used but not defined herein have the meaning given to them in the PJM Open Access Transmission Tariff ("Tariff").

4. I have previously submitted affidavits and prepared materials in support of another complaint involving PJM RTEP cost allocations, which is currently pending before the Federal Energy Regulatory Commission ("FERC") in Docket No. EL15-67, and I have supported filings in Docket Nos. EL14-1485 and EL14-972, which also relate to PJM OATT Schedule 12-Appendix A updates to include additional RTEP projects and their respective cost allocations.

5. The Artificial Island Project ("AI Project") is a group of several projects whose objective, as stated by PJM, is to "improve operational performance on bulk electric system facilities in the Southern New Jersey, Artificial Island area, site of PSE&G's Salem 1 and 2 and Hope Creek 1 nuclear generating plants".[1] These plants (the "AI Plants"), which are physically adjacent to each other along the eastern shore of the Delaware River, interconnect to the PJM 500 kV transmission system at substations located within each facility.

6. A major component of the AI Project is construction of a new 230 kV submarine cable transmission line under the Delaware River to connect the 500 kV system to which Artificial Island generation currently interconnects to a 230 kV corridor in Delaware that runs generally north-south several miles inland from the Delaware River's western shore. This new connection essentially affords additional network connectivity for the AI Plants to facilitate full delivery of their combined output (3,818 MW) without operating restrictions and special protection systems that have historically been in place.

7. This new 230 kV submarine cable transmission line was selected as part of a competitive solicitation process administered by PJM. Although patterned after PJM's Order 1000 tariff provisions, this process began prior to full implementation of the Order 1000 competitive solicitation process, and is considered by PJM to be a "trial run" of that process.[2] This particular project was proposed by, and its main component – the 230 kV submarine cable – has been assigned to be built by LS Power (a private company) and

[1] *See* Artificial Island Project Recommendation White Paper at Section 1.0.1, *available at* http://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx ("White Paper").
[2] *See id*. at 5, n. 1.

not one of the PJM Transmission Owners ("TOs"). Certain PJM TOs will construct the portions of the overall project that involve work within their existing facilities.

8. PJM received 26 separate proposal packages from several different sponsors in response to its Artificial Island solicitation. Project concepts ranged in cost from approximately $100 million to $1.55 billion, and covered a range of facility types and technologies – substation upgrades, new AC transmission lines, DC transmission systems, and dynamic reactive devices to name a few. These projects also covered a varied geographic area generally between southern New Jersey, eastern Pennsylvania, northern Delaware, and northeastern Maryland. The proposal concepts spanned many PJM TO zones, including Public Service Electric and Gas, Jersey Central Power and Light, Atlantic City Electric, PECO, Delmarva Power and Light, and Baltimore Gas and Electric.

9. Following an initial evaluation of all proposals, PJM selected five proposals for which it would perform a detailed evaluation and from which it would develop a recommended solution. Following this further evaluation, PJM recommended the following projects as its Artificial Island solution:

- A new 230 kV submarine cable between Salem (in NJ) and a new substation ("Silver Run") tapping the existing Red Lion-Carranza and Red Lion-Cedar Creek 230 kV lines (in DE);
- A 300 Mvar dynamic reactive device at PSE&G's New Freedom substation;
- Establishment of high speed optical ground wire communications on several existing critical 500 kV circuits in the vicinity of Artificial Island;

- Adjustment of fixed tap settings on AI Plant Generator Step Up (GSU) transformers.

These overall projects have been organized by PJM into Baseline Upgrade project b2633 with ten sub-projects b2633.1 – b2633.10. The total estimated cost for all projects is $275.23 million. Of this total, the Delmarva transmission Zone has been allocated $246.42 million, or 89.46% of the total cost.[3] Details of cost allocations to various Zones for the sub projects can be seen in Exhibit 2 to this Affidavit, which was provided by PJM at the request of the DE PSC.

10. The purpose of my affidavit is not to challenge PJM's project evaluation and selection process, or to challenge the cost estimates for the overall AI Project or its sub-projects. My Affidavit will focus on the fact that PJM's existing cost allocation methodology, and specifically the component of PJM's existing cost allocation methodology that uses solution-based DFAX as its core methodology, has determined cost allocations with respect to the AI Project that are unjust, unreasonable, unduly discriminatory and preferential, and do not allocate costs in a manner that is roughly commensurate with the benefits of the AI Project.

11. PJM uses a methodology it calls "solution-based DFAX" to allocate all or part of the costs of certain RTEP projects (Regional Facilities and Low Voltage Facilities whose cost is estimated to equal or exceed $5 million) to Responsible Zones (which include load Zones and Merchant Transmission Facilities ("MTFs"), or "Zones" for the purposes of this Affidavit). This methodology was implemented and described in the PJM TO's compliance filing in Docket No. ER13-90-002 on July 22, 2013. The Solution-based DFAX methodology uses distribution factors ("DFAX") that are calculated by power

[3] *See id.* at 38.

flow simulations to determine the percentage of a Zone's total power flow (the "DFAX value") on various transmission system facilities that comprise the system being studied.

12. The solution-based DFAX methodology specifically examines a power system under peak load conditions where not-yet-constructed RTEP projects are included in the power flow model so that component flows on a RTEP project's facilities can be calculated. DFAX values are a per unit value, expressed as a decimal number or as a percentage, representing the portion of a Zone's own aggregate total load that will flow on a given facility. DFAX values are calculated in the power flow models for each individual Zone.

13. PJM refers to the power flow it calculates over a particular facility as "MW usage." PJM calculates a Zone's MW usage of a particular transmission facility by multiplying the individual Zone's DFAX value on the examined facility by the Zone's peak planning load. This MW usage value for each Zone is intended to represent a proxy of the benefit received from the RTEP project by each Zone. However, the cost allocation calculation methodology PJM employs with solution-based DFAX does not necessarily account for all of the benefits received by a Zone due to an RTEP project, nor does it necessarily identify other beneficiaries that may enjoy benefits from the project. For example, if a facility is intended to resolve a short circuit violation rather than to relieve a power flow based constraint, PJM does not allocate costs using short-circuit calculations where contributions to the violation or receipt of benefits can be measured. Similarly, when a direct operational benefit or cost savings is realized from including a project in the RTEP, this benefit is not quantified as part of the overall solution-based DFAX approach. Instead, PJM exclusively uses the power flow-based MW-usage approach that focuses on

usage of the transmission facility calculated from a distribution factor under peak load conditions.

14. The AI Project objective is to improve the ability to transmit the total amount of AI Plant output (3,818 MW) to the PJM transmission system while avoiding the limits that have been imposed by legacy operating constraints. Delivery of this power using the existing system creates reliability criteria violations and operational issues that effectively prevent unconstrained operation of the AI Plants. As such, the AI Plants' ability to operate at their full capabilities and transact capacity and energy in the PJM marketplace, constrained in the existing system, would seem to be achieved by construction of the AI Project.

15. Further, the AI Plants' ability to fully transmit capacity and energy into the market would also benefit load zones that can now procure unconstrained products from the AI Plants. This release of prior constraints adds to available supply in the marketplace, which tends to reduce prices and enhance market efficiency. Also, other resources that may have been constrained by the existing system due to the AI Plants' use of the system's capability may now be able to participate more effectively in the marketplace. I have reviewed the PJM market efficiency analysis, which shows the energy market price-reducing benefits of the AI Project throughout the PJM system. That PJM analysis demonstrates clearly that many Zones, in addition to the Delmarva Zone, materially and substantially benefit from the AI Projects. I note that the PJM analysis focused only on the benefits to load; it does not incorporate the obvious benefits of the AI Project to the AI Plants and to other resources that benefit from increased transfer capability. PJM's own analysis, which PJM conducted at the request of the DE PSC, finds that only about

10% of the total projected annual load payment savings will accrue to the Delmarva Zone, despite the Delmarva Zone being allocated 89.46% of the total estimated cost as mentioned above. And, as noted, this percentage of benefits that accrues to the Delmarva Zone do not account for the benefits that the AI Plants will receive from the AI Project. If all benefits of the AI Project are taken into account, the Delmarva Zone's share of the benefits would likely be less than 10%.

16. This gross misalignment of costs and benefits for the Delmarva Zone can also be attributed to the somewhat arbitrary nature of where the project selected by PJM connects to the existing system. As evidenced by the multiple proposals received in the Artificial Island solicitation process, there were several ways to solve for the objective of the AI Project, involving several different geographic areas and load zones. If another project concept would have been selected through PJM's evaluation, and that project connected into a different load zone, then that load Zone would likely have seen a disproportionate cost allocation and Delmarva would have been spared. The fact that other Zones could have just as easily been the "sink" point for the new transmission line underscores the arbitrariness of the cost allocation determinations for the AI Project.

17. Note that the delivery of power out of the Artificial Island area does not just benefit the immediate system to which the transmission lines out of the area connect, but instead allows other loads on the PJM bulk power system to access these resources. In a sense, portions of the additional power deliveries can be thought of as being wheeled through the immediately adjacent systems, such as Delmarva, for the benefit of other loads in PJM. This is in contrast to a situation where a load pocket is located within a constrained transmission area, and any improvements to deliver power into this constrained area

solely benefit the load in that area. A significant root cause of the disproportionate cost allocations associated with the AI Project is the "one-size-fits-all" way in which PJM applies solution-based DFAX to all projects subject to solution-based DFAX cost allocation as defined in PJM OATT Schedule 12 (*i.e.*, 50% for Regional Facilities and 100% for Lower Voltage Facilities). The concept of a cost allocation methodology using distribution factors *could* be a reasonable basis for determining usage and, by proxy, some of the benefits realized by a load due to the addition of a new transmission facility. However, the solution-based DFAX methodology prescribed in Schedule 12 falls very short of achieving reasonable outcomes in certain circumstances, such as the AI Project.

18. Of the many shortcomings of solution-based DFAX (and discussed in the other FERC dockets I mentioned earlier in this Affidavit (such as the 1% *de minimis* threshold and netting)), one is that it fails to recognize the benefits realized through the inherent reliability enhancement achieved by establishing additional or enhanced connectivity in a network. Put simply, distribution factors calculated under solution-based DFAX only facilitate measurement of the proxy use of the transmission system with all transmission elements in service at peak load. This is a limited snapshot of the system obtained by studying and evaluating results from one very narrow set of assumptions. In reality, the performance of the system under outage conditions is what matters in evaluating the transmission system under applicable reliability criteria. This involves multiple snapshots of the system during outages of varying system elements and is a fundamental aspect of operating a secure power system. I have not performed any specific simulations to test this as concerns the AI Project, but it seems highly likely that contingency testing around the AI Project could provide a more accurate – and probably a far different –

determination of beneficiaries for the AI Project than does the solution-based DFAX approach.

19. It is clear from the Artificial Island situation that the current cost allocation methodology is not working as intended to align cost responsibility with project benefits in all instances. There is ample evidence that further modifications are necessary to establish a cost allocation methodology that consistently aligns costs and benefits. Distribution factors may still play a role in cost allocation, but it is apparent that their use in the current methodology, as evident with respect to the AI Project, is leading to anomalous, and perhaps even absurd, results in certain instances.

20. This concludes my Affidavit.

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EDUCATION

Master of Engineering, Electric Power Engineering, Rensselaer Polytechnic Institute, Troy, NY (August, 1988).

- **Research Assistantship -** Distribution transformer statistical inventory optimization and failure prediction.
- **GPA:** 3.9/4.0, 4.0/4.0 for electric power course work.

Bachelor of Science, With Distinction, Worcester Polytechnic Institute, Worcester, MA (May, 1985).

- **Projects -** ***MQP*** involved design, construction, and testing of an automatic synchronizer for an A.C. generator; ***IQP*** was research, development, and production of a television program exploring the possibilities of high-speed rail travel on the Northeast Corridor.

WORK EXPERIENCE

October, 2000-Present: **Principal and Founding Partner,** Energy Initiatives Group, LLC, Marlborough, MA

- Provides consulting, engineering, and project management services for electric and energy services clients that include generation and transmission developers, system operators, large electric users, and traditional utilities.
- Active in many areas associated with the deregulated electric energy industry, including merchant generation, merchant transmission, interconnection studies and processes, tariffs and regulatory processes, distributed generation, and renewable resource development.
- Involved in developing, siting, engineering, and constructing projects nationwide that include large generation, AC and DC transmission, high-speed rail, and distributed generation.

April, 1999-October, 2000: **President and Founder,** JMEnergy, Inc., Holliston, MA

- Provided engineering and consulting services to generation developers and host utility companies to design, manage, and coordinate generator interconnections and facility design/construction.
- Acted as owner's engineer for new generator interconnections totaling over 3750 MW in Texas and New England.
- Managed the host utility interface for projects under development nationwide, including Texas, California, New Mexico, New York, Missouri, and West Virginia.
- Evaluated and studied special technical and power quality issues associated with several interconnections including effects of large arc furnace loads located close to generators and performance of harmonic filters associated with electric traction supply systems.

July, 1992 -April, 1999: **Principal Engineer,** PLM Electric Power Engineering, Hopkinton, MA.

- Performed project management, design, contracting, and consulting for clients in the electric utility, transportation, and manufacturing industries.
- Prepared specifications, drawings, contracts, budgets, schedules, and other related technical and non-technical aspects of design project management, including technical supervision and guidance of engineers and designers.

August, 1988-July, 1992: **Engineer,** Electrical Stations Engineering, New England Power Service Company, Westboro, MA.

- Designed, estimated, and supported construction for new and existing transmission and distribution substations.
- Engineered and designed critical power supply systems for mainframe dispatching computer systems.

June, 1985-August, 1987: **Associate Field Engineer,** Massachusetts Electric Company, Hopedale, MA.

- Designed, estimated, and supervised construction of electric distribution facilities and customer connections.
- Supervised clerical, technical, and construction personnel during normal, off hour, and emergency situations; planned, directed, and performed system switching and storm restoration operations.

REGISTRATION Registered Professional Engineer in Massachusetts, Connecticut, and Rhode Island.

PROFESSIONAL ORGANIZATIONS Member, IEEE, NSPE, and Eta Kappa Nu; Chair (2007-2008) of NYISO Transmission Planning Advisory Subcommittee (TPAS). Chair (2010) of NYISO Operating Committee.

Exhibit No. 2

PJM Market Efficiency Study
Artificial Island Benefits

Requested by Delaware Public Service Commission

Study Assumptions

Market Efficiency Project Study approach:

- Utilized PJM Market Efficiency Base Case for study year 2019
- Compared LMP and Load Payments between the following scenarios for both a single hour* and annual value:
  - System without Artificial Island solution and one Salem Unit Offline**
  - System with Artificial Island solution and all Salem Units Online

** Single hour derived from RTO* Coincident Peak using 2019 Base Simulation
***Annual assumes one Salem unit offline for entire simulated year.*

Results using RTO Coincident Peak Hour

- RTO Coincident Peak hour from simulation: July 31, 2019
- RTO Peak Load from simulation: 155,382 MWs

- Simulation results show that the Artificial Island project decreases LMP in Delmarva Zone (DPL) for the Peak hour by $3.5/MWh and Load Payments by $13,772/h.
  - Base case assumes no Artificial Island solution and one Salem Unit offline.

Annual LMP Benefits Due To Artificial Island Solution*

- During the peak months of July and August, the market simulation shows an average LMP decrease in DPL Zone of 2.20 $/MWh and 1.90 $/MWh, respectively.
- The annual LMP average across DPL decreases by 0.86 $/MWh.
- The PJM average LMP decreases by 0.52 $/MWh in July, and 0.30 $/MWh in August.

LMP Avg. Benefits Due to Artificial Island Solution (negative value is a benefit, a decrease in LMP)

Area	Month 1	2	3	4	5	6	7	8	9	10	11	12	Annual Average
AECO	$(0.15)	$(0.26)	$(0.82)	$(0.80)	$(0.18)	$(0.72)	$(1.79)	$(1.27)	$(1.01)	$(0.35)	$(0.48)	$(0.71)	$ (0.77)
AEP	$(0.23)	$(0.32)	$(0.01)	$(0.10)	$ 0.11	$(0.02)	$(0.11)	$(0.01)	$(0.10)	$ 0.25	$(0.19)	$ 0.01	$ (0.06)
APS	$(0.01)	$(0.19)	$(0.35)	$(0.11)	$ 0.38	$(0.07)	$(0.22)	$(0.11)	$(0.24)	$ 0.18	$(0.23)	$(0.06)	$ (0.09)
BGE	$ 0.04	$ 0.14	$(0.47)	$(0.20)	$ 0.20	$(0.12)	$(0.41)	$(0.17)	$(0.47)	$(0.06)	$(0.35)	$(0.28)	$ (0.18)
COMED	$(0.22)	$(0.29)	$ 0.44	$(0.36)	$(0.08)	$ 0.02	$(0.05)	$ 0.08	$ 0.01	$ 0.01	$ 0.48	$ 0.15	$ 0.02
DAY	$(0.31)	$(0.49)	$ 0.16	$(0.05)	$(0.00)	$(0.01)	$(0.09)	$ 0.00	$(0.06)	$ 0.44	$(0.15)	$(0.00)	$ (0.05)
DEOK	$(0.28)	$(0.47)	$ 0.20	$(0.14)	$(0.04)	$(0.02)	$(0.08)	$ 0.00	$(0.05)	$ 0.53	$(0.11)	$(0.01)	$ (0.04)
DOM	$ 0.02	$ 0.28	$(0.33)	$(0.04)	$ 0.31	$ 0.02	$(0.16)	$(0.03)	$(0.09)	$ 0.07	$(0.47)	$(0.16)	$ (0.05)
DPL	$(0.19)	$(0.22)	$(0.85)	$(0.70)	$(0.27)	$(0.77)	$(2.20)	$(1.90)	$(1.05)	$(0.36)	$(0.57)	$(0.77)	$ (0.86)
DUQ	$(0.16)	$(0.10)	$(0.69)	$(0.37)	$ 0.42	$(0.15)	$(0.23)	$(0.12)	$ 0.12	$ 0.70	$(1.04)	$(0.10)	$ (0.14)
EKPC	$(0.22)	$(0.38)	$ 0.11	$ 0.01	$ 0.03	$(0.01)	$(0.06)	$ 0.05	$(0.09)	$ 0.27	$(0.14)	$(0.01)	$ (0.05)
FE-ATSI	$(0.07)	$(0.20)	$(0.30)	$(0.38)	$ 0.22	$(0.15)	$(0.21)	$(0.08)	$(0.04)	$ 0.40	$(0.54)	$(0.07)	$ (0.12)
JCPL	$(0.12)	$(0.28)	$(0.71)	$(0.44)	$ 0.07	$(0.61)	$(1.52)	$(1.02)	$(0.85)	$(0.23)	$(0.41)	$(0.58)	$ (0.59)
METED	$ 0.00	$(0.12)	$(0.78)	$(0.62)	$(0.15)	$(0.62)	$(1.18)	$(0.69)	$(1.15)	$(0.24)	$(0.38)	$(0.46)	$ (0.54)
PECO	$(0.10)	$(0.24)	$(0.68)	$(0.61)	$(0.12)	$(0.63)	$(1.79)	$(1.23)	$(0.91)	$(0.22)	$(0.40)	$(0.63)	$ (0.66)
PENELEC	$ 0.12	$ 0.03	$(0.14)	$(0.51)	$ 0.05	$(0.41)	$(0.64)	$(0.44)	$(0.55)	$(0.16)	$(0.11)	$(0.19)	$ (0.24)
PEPCO	$ 0.03	$ 0.23	$(0.37)	$(0.03)	$ 0.36	$ 0.03	$(0.22)	$(0.05)	$(0.17)	$ 0.01	$(0.37)	$(0.20)	$ (0.06)
PLGRP	$(0.04)	$(0.15)	$(0.69)	$(0.45)	$(0.04)	$(0.56)	$(1.22)	$(0.80)	$(0.79)	$(0.15)	$(0.31)	$(0.50)	$ (0.48)
PSEG	$(0.16)	$(0.28)	$(0.70)	$(0.45)	$ 0.05	$(0.58)	$(1.49)	$(1.00)	$(0.81)	$(0.08)	$(0.59)	$(0.62)	$ (0.59)
RECO	$(0.35)	$(0.88)	$(1.95)	$(0.14)	$ 0.44	$(0.69)	$(0.93)	$(0.71)	$(0.65)	$ 0.09	$(0.81)	$(0.41)	$ (0.59)
PJM	$(0.11)	$(0.15)	$(0.25)	$(0.27)	$ 0.10	$(0.19)	$(0.52)	$(0.30)	$(0.31)	$ 0.09	$(0.25)	$(0.18)	$ (0.20)

*Simulation assumes one Salem unit offline for entire year.

Annual Load Payment Savings Due To Artificial Island Solution*

- During the peak months of July and August, the market simulation shows a decrease of the monthly load payments across DPL zone of $4.32 million and $3.64 million, respectively.
- The annual total load payments across DPL zone decreases by $17.04 million.
- The PJM annual total load payments decrease by $169.2 million.

Load Payments Savings Due to Artificial Island Solution ($ million, negative value is a benefit, a decrease in load payments)

Area	Month												
	1	2	3	4	5	6	7	8	9	10	11	12	Annual Total
AECO	$ (0.14)	$ (0.22)	$ (0.67)	$ (0.60)	$ (0.15)	$ (0.73)	$ (2.13)	$ (1.46)	$ (0.91)	$ (0.28)	$ (0.38)	$ (0.64)	$ (8.28)
AEP	$ (2.82)	$ (3.54)	$ (0.13)	$ (0.99)	$ 1.16	$ (0.21)	$ (1.34)	$ (0.17)	$ (1.05)	$ 2.57	$ (1.98)	$ 0.06	$ (8.43)
APS	$ (0.04)	$ (0.84)	$ (1.49)	$ (0.43)	$ 1.48	$ (0.29)	$ (0.97)	$ (0.51)	$ (0.93)	$ 0.73	$ (0.91)	$ (0.28)	$ (4.46)
BGE	$ 0.14	$ 0.39	$ (1.31)	$ (0.50)	$ 0.52	$ (0.35)	$ (1.37)	$ (0.55)	$ (1.29)	$ (0.14)	$ (0.91)	$ (0.83)	$ (5.22)
COMED	$ (2.09)	$ (2.47)	$ 3.78	$ (2.89)	$ (0.71)	$ 0.14	$ (0.49)	$ 0.82	$ 0.08	$ 0.08	$ 4.04	$ 1.41	$ 1.70
DAY	$ (0.52)	$ (0.73)	$ 0.24	$ (0.07)	$ (0.00)	$ (0.02)	$ (0.15)	$ 0.00	$ (0.09)	$ 0.64	$ (0.21)	$ (0.00)	$ (0.92)
DEOK	$ (0.70)	$ (1.04)	$ 0.45	$ (0.28)	$ (0.09)	$ (0.04)	$ (0.22)	$ 0.00	$ (0.10)	$ 1.14	$ (0.24)	$ (0.02)	$ (1.16)
DOM	$ 0.17	$ 2.46	$ (2.86)	$ (0.32)	$ 2.53	$ 0.19	$ (1.58)	$ (0.26)	$ (0.80)	$ 0.57	$ (3.95)	$ (1.49)	$ (5.33)
DPL	$ (0.34)	$ (0.35)	$ (1.35)	$ (0.99)	$ (0.40)	$ (1.30)	$ (4.32)	$ (3.64)	$ (1.66)	$ (0.53)	$ (0.85)	$ (1.32)	$ (17.04)
DUQ	$ (0.22)	$ (0.13)	$ (0.88)	$ (0.43)	$ 0.51	$ (0.21)	$ (0.35)	$ (0.17)	$ 0.15	$ 0.36	$ (1.27)	$ (0.14)	$ (2.26)
EKPC	$ (0.26)	$ (0.39)	$ 0.10	$ 0.01	$ 0.03	$ (0.01)	$ (0.06)	$ 0.05	$ (0.08)	$ 0.23	$ (0.13)	$ (0.01)	$ (0.53)
FE-ATSI	$ (0.44)	$ (1.13)	$ (1.76)	$ (2.03)	$ 1.22	$ (0.89)	$ (1.36)	$ (0.50)	$ (0.23)	$ 2.19	$ (2.96)	$ (0.40)	$ (8.28)
JCPL	$ (0.25)	$ (0.53)	$ (1.37)	$ (0.77)	$ 0.13	$ (1.34)	$ (3.90)	$ (2.52)	$ (1.71)	$ (0.42)	$ (0.75)	$ (1.19)	$ (14.62)
METED	$ 0.00	$ (0.16)	$ (1.08)	$ (0.78)	$ (0.19)	$ (0.88)	$ (1.80)	$ (1.04)	$ (1.53)	$ (0.31)	$ (0.50)	$ (0.68)	$ (8.96)
PECO	$ (0.39)	$ (0.81)	$ (2.38)	$ (1.93)	$ (0.39)	$ (2.35)	$ (7.56)	$ (5.05)	$ (3.20)	$ (0.72)	$ (1.33)	$ (2.32)	$ (28.46)
PENELEC	$ 0.22	$ 0.04	$ (0.24)	$ (0.79)	$ 0.08	$ (0.65)	$ (1.09)	$ (0.76)	$ (0.88)	$ (0.26)	$ (0.18)	$ (0.34)	$ (4.87)
PEPCO	$ 0.08	$ 0.59	$ (0.95)	$ (0.07)	$ 0.91	$ 0.07	$ (0.73)	$ (0.15)	$ (0.45)	$ 0.04	$ (0.89)	$ (0.55)	$ (2.10)
PLGRP	$ (0.15)	$ (0.55)	$ (2.58)	$ (1.49)	$ (0.12)	$ (2.00)	$ (4.72)	$ (3.09)	$ (2.70)	$ (0.50)	$ (1.08)	$ (2.00)	$ (20.97)
PSEG	$ (0.61)	$ (0.96)	$ (2.54)	$ (1.50)	$ 0.20	$ (2.40)	$ (6.98)	$ (4.55)	$ (3.11)	$ (0.29)	$ (2.02)	$ (2.33)	$ (27.10)
RECO	$ (0.04)	$ (0.10)	$ (0.23)	$ (0.02)	$ 0.05	$ (0.10)	$ (0.15)	$ (0.11)	$ (0.09)	$ 0.01	$ (0.09)	$ (0.05)	$ (0.92)
PJM	$ (8.40)	$ (10.46)	$ (17.24)	$ (16.88)	$ 6.77	$ (13.35)	$ (41.29)	$ (23.66)	$ (20.57)	$ 5.61	$ (16.58)	$ (13.13)	$ (169.20)

*Simulation assumes one Salem unit offline for entire year.

Distribution Factor Allocations

DFAX ALLOCATIONS WITH AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.7%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.5%	0.0%	0.0%	47.0%	1.9%
Salem - Hope Creek	22.8%	1.1%	0.0%	0.0%	41.4%	4.4%	0.0%	0.0%	0.0%	0.0%	29.1%	1.2%
Salem - Orchard	8.2%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.6%	0.0%	0.0%	46.5%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	17.1%	2.0%	1.5%	20.6%	0.0%	0.0%	54.9%	2.2%
Hope Creek - New Freedom	7.7%	0.0%	0.0%	1.3%	16.8%	1.8%	1.2%	22.4%	0.0%	0.0%	47.0%	1.9%
Hope Creek - Red Lion	1.9%	36.0%	29.4%	1.2%	3.2%	0.3%	1.7%	0.0%	0.0%	26.3%	0.0%	0.0%

DFAX ALLOCATIONS WITHOUT AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.6%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	22.9%	0.0%	0.0%	46.8%	1.9%
Salem - Hope Creek	21.2%	3.8%	7.7%	0.0%	41.2%	4.4%	0.0%	0.0%	0.0%	0.0%	20.9%	0.9%
Salem - Orchard	8.1%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	23.1%	0.0%	0.0%	46.2%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	16.9%	2.0%	1.5%	21.0%	0.0%	0.0%	54.7%	2.2%
Hope Creek - New Freedom	7.6%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.8%	0.0%	0.0%	46.7%	1.9%
Hope Creek - Red Lion	0.6%	26.1%	51.6%	0.9%	1.1%	0.1%	1.3%	0.0%	0.1%	18.3%	0.0%	0.0%

John J. Marczewski

STATE OF NEW JERSEY)
) SS
COUNTY OF UNION)

Subscribed and sworn to before me this 28th day of August, 2015.

Notary Public

ANGIE DIAZ
NOTARY PUBLIC OF NEW JERSEY
I.D. # 2430389
My Commission Expires 2/25/2018