



Transmission Expansion Advisory Committee
(TEAC) Artificial Island
Recommendations to the PJM Board

PJM Staff Whitepaper
April 2017





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Executive Summary

At its August 2016 meeting, the PJM Board of Managers voted to suspend all aspects of the Artificial Island project due to the uncertainties resulting from increased cost estimates, permitting challenges, and the receipt of new technical information from PSE&G. Stakeholders were notified via a communication from PJM CEO Andy Ott, the text of which follows:

Dear Members and Stakeholders of PJM: PJM has been working with transmission owners and developers to resolve operational voltage and stability problems in the area known as Artificial Island in southern New Jersey. This is a very complex project, compounded by the unique design of the electrical system and geography of the area. It has become evident to all involved that the projected costs to resolve the problems at Artificial Island have increased significantly. PJM has been examining alternatives in an attempt to offset some of the increases. In addition, questions have arisen about whether the currently proposed solution would perform as intended without further expense. Because of these concerns, PJM has come to the conclusion that a pause in the project is necessary before any new financial obligations are incurred by the project developers. At this time, the PJM Board is suspending all elements of the Artificial Island project and directing PJM to perform a comprehensive analysis to support a future course of action. In light of the current uncertainties around the changing scope and configuration of the project, it is imperative that we understand the basis for any alternatives that may exist to manage the operational issues at Artificial Island. The Board has asked for the review to be completed by February 2017, at which time PJM will be in a position to decide how best to proceed. Background information and details leading to this decision are outlined in a letter from Steven Herling, PJM's Vice President of Planning, to the PJM membership and stakeholders.

PJM's approach to the review was to form multiple assessment teams, supplemented by external consulting resources, to conduct data-driven analyses of the factors involved in the decision making process. PJM performed detailed reviews of the originally approved project (see **Appendix 1** and **Figure 1**) and a number of the projects on the "short list" from the initial recommendation (see **Appendix 4**). These reviews included analytical work using updated assumptions to assess the performance of proposals, constructability and permitting reviews, cost estimate and cost cap reviews. Engineering and Legal consultants were engaged to assist with the constructability, permitting, cost estimate and cost cap reviews. Based on these reviews and in consideration of the additional information provided by PSE&G and its incorporation into the PJM analysis, PJM staff recommended lifting the suspension on the previously approved 230kV transmission line project, primarily designated to LS Power, with the following modifications:

- Remove the New Freedom Static VAR Compensator (SVC) and various optical ground wire (OPGW) installations from the project scope;
- Change the 230 kV line termination point from Salem to Hope Creek;
- Modify existing operational voltage schedule and associated bandwidth for all of the units at Artificial Island; and
- Amend or retire the existing Artificial Island Operating Guide (AIOG)



The modifications described above are anticipated to result in a reduction to the estimated project cost of approximately \$150 million as compared to the February 2016 cost estimate, which included costs provided by PSE&G. (see **Table 1** and **Appendix 3**)

As part of a joint effort with PSE&G and LS Power, alternative options were identified and investigated as a means to reduce the cost and complexity of interconnecting the new 230 kV line at Artificial Island. The options considered were not part of the original competitive solicitation, but modifications considered after the project was designated and engineering started. Of the different options identified, two options were considered in further detail, and ultimately the Hope Creek 2B option was selected as the preferred interconnection point at Artificial Island. PJM's assessment of constructability risk factors concluded that the change of the connection of the 230kV transmission line from Salem to Hope Creek will reduce constructability risk due to the avoidance of working inside the Salem reactor building where the existing transmission protective relays are housed. PJM's conclusions on constructability, siting and permitting risks, and the relative financial risks associated with the PSE&G and LS Power cost containment proposals were affirmed by an engineering consultant and external legal counsel. Specifically, the constructability, siting and permitting risks associated with the PSE&G 500kV proposal were viewed as more complex and subject to increased execution risk. Further, any mitigation required to obtain necessary permits was likely to result in additional costs that would allow PSE&G to invoke the exceptions included in their cost cap terms and conditions. The risks associated with the LS power proposal were considered challenging but more achievable and the terms of their cost cap language provide greater cost certainty due to the limits of exclusions. (See **Appendices 3 and 4**)

As discussed in **Appendix 3**, the cost estimates for the LS Power and PSE&G proposals are \$280 million and \$254 million, respectively. Of the PSE&G proposal estimate, \$221 million is within their cost containment mechanism as discussed above. Prior to suspension, LS Power had completed substantial engineering, design and procurement activities amounting to \$6.4 million. Further, these efforts resulted in the execution of a fixed price contract for the submarine portion of the project, the completion of significant preliminary engineering work and the acquisition of all private land in Delaware required for the project. Based upon these efforts, LS Power currently estimates the cost of their portion of the project to be \$13 million below their cap, providing a high degree of certainty that the final costs will be at or below the cap.

The PJM analyses confirm that the above-described modifications can be implemented without sacrificing reliability while still addressing the operational performance issues that formed the basis for the initial project solicitation. PJM staff recommended moving forward with the project described in this white paper as there are significant risks associated with not proceeding with a solution, i.e. the "do-nothing" alternative. (See **Appendix 2**). The combination of the installation of the 230kV transmission line and the imposition of a minimum voltage requirement for Artificial Island units provides a robust and complete solution that addresses the operational flexibility issues.

Figure 1 – PJM Board Approved Artificial Island Project Component: Salem – Silver Run 230 kV Line

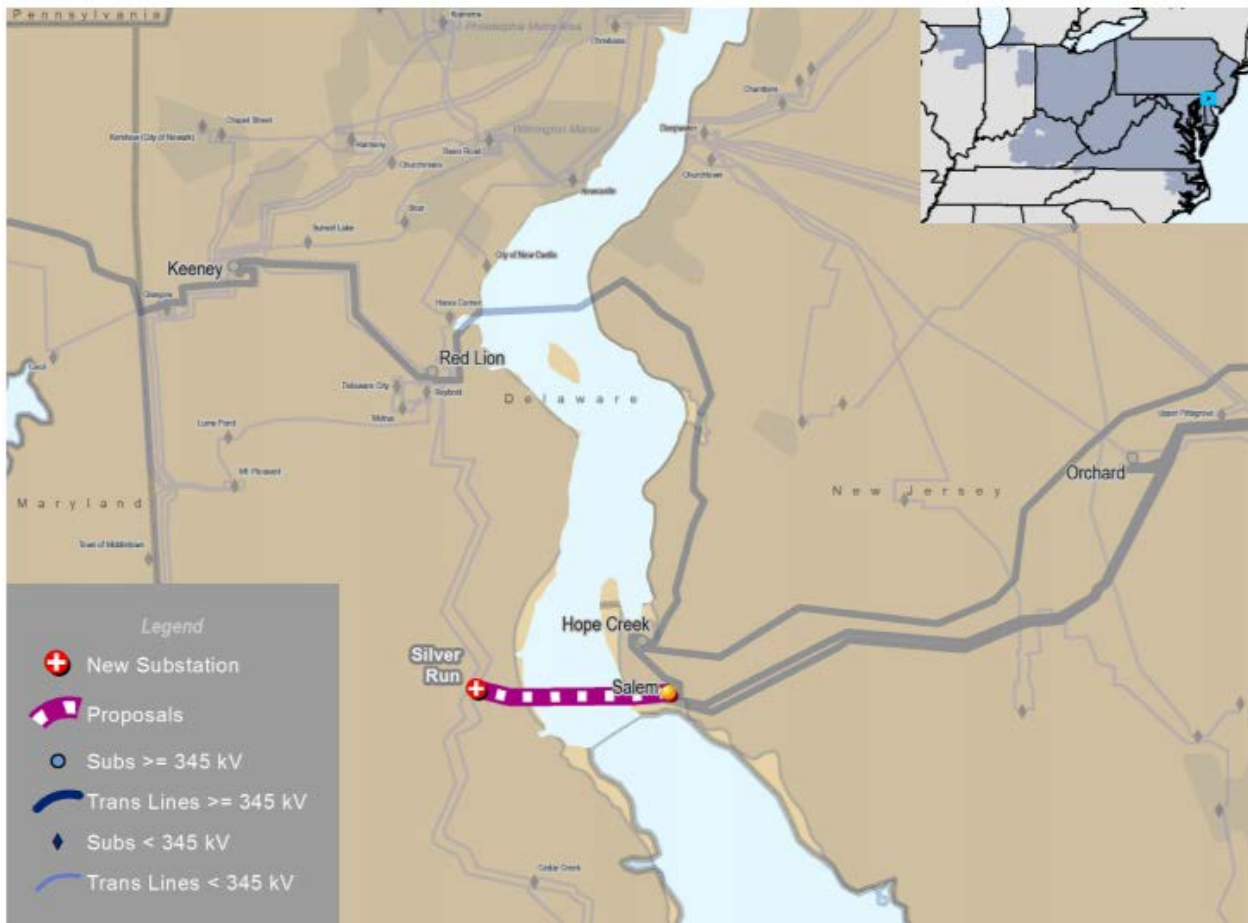




Table 1 – Artificial Island Cost Estimate Summary

Project Components (all costs in millions)	Approved Artificial Island Project	PSE&G Cost Update February 2016	2B Hope Creek W/Out SVC or OPGW
230kV Line and Silver Run Substation (LSP)	\$146	\$146	\$146
Salem Interconnection (PSE&G)	\$61 - 74 ¹	\$152	
Hope Creek 2B Interconnection (PSE&G)			\$132
OPGW (PSE&G)	\$25 ¹	\$39	
New Freedom SVC (PSE&G)	\$38 ¹	\$81	
DE Interconnection (PHI)	\$2 ¹	\$2 ¹	\$2 ¹
Project Total	\$272 - \$285	\$420	\$280

¹ Costs include PJM calculated contingency

PJM Analysis

1.0 Background

Subsequent to the PJM Board's approval of the Artificial Island project in July 2015, PSE&G and PSEG Power submitted to PJM new technical information as follows:

- Protection system clearing times -- based on the installation of new relays. (PSE&G)
- Artificial Island generator step-up (GSU) transformer modeling data -- based on installation of new GSUs. (PSEG Power)
- Artificial Island generation dynamics models -- based on installation of new excitation systems on the Salem and Hope Creek generators. (PSEG Power)
- Updated impedances for the proposed 500/230kV transformer at the Artificial Island end of the Delaware River underwater cable to conform with PSE&G's standard 500/230 kV transformer specification. (Collaborative effort between PSE&G, PJM and LS Power)

The introduction of this new information called into question the validity of the existing version of the AIOG as well as the modeling assumptions underlying PJM's RTEP process studies that drove Artificial Island project decision-making. In addition PSE&G also provided substantially higher cost estimates, based on initial engineering and design activities, than PJM staff had developed for their work at Salem, the OPGW installation and protective relay upgrades, and the installation of the SVC at New Freedom. Based on the cost estimate information and the unknown impacts of the new technical information, including the possibility that the scope of the solution might need to be increased, the PJM Board decided, on August 3, 2016, to temporarily suspend all elements of the project and directed PJM staff to complete a comprehensive review including an assessment of the efficacy of the existing AIOG limiting contingency assumptions in light of the updated relay clearing times, review the scope of the approved project, and reconsider alternative proposed solutions.

PJM conducted studies to analyze alternative connection options for the 230 kV transmission line and contracted for additional constructability reviews by consultants, a review of the Fixing America's Surface Transportation Act (FAST) act impact to permitting, and a review of the various aspects of the cost containment terms and conditions of proposed projects. PJM staff completed exhaustive technical analyses including stability studies to understand the impact of revised control and protection clearing times on both the existing system configuration as well as the proposed system configuration. In addition, operating history reviews were completed to develop alternative voltage control strategies for operation of the generation at Artificial Island.

Historical operating analysis entailed a review of four and a half years of data, under the following four operating scenarios:



1. All Three Artificial Island generating units and all 500kV transmission facilities in service;
 - 5015 (Hope Creek-Red Lion)
 - 5021 (Salem-Orchard)
 - 5023 (Hope Creek-New Freedom)
 - 5024 (Salem-New Freedom)
 - 5037 (Hope Creek-Salem)
 - Remote line – 5038 (New Freedom-East Windsor)
2. Two Artificial Island units in service, all lines in service
3. One Artificial Island unit in service, all lines in service
4. All Artificial Island units in service, one critical line out of service

2.0 Assessment of Operations Using Updated Assumptions from PSE&G

2.1 Relay Settings Updated by PSE&G

PSE&G notified PJM in April 2016 that key protective relay setting assumptions on facilities at the Artificial Island substations had changed. PSE&G had upgraded line protective relay technology such that the fault clearing time for specific *bus* faults with a stuck breaker delayed clearing scenario was now longer than the fault clearing time for a *line* fault with stuck breaker delayed clearing scenario that was historically the most limiting. This information is critical since a longer clearing time is expected to have a negative impact on stability performance compared to the same scenario with a shorter clearing time. This new information triggered a review of PJM's operating and planning assumptions. PJM's first step was to evaluate the impact of the new PSE&G *bus* and *line* clearing time assumptions by performing a detailed review of the protective relay schemes and associated clearing times with the PSE&G protection staff. These discussions confirmed that all of the transmission line protection schemes had been upgraded with microprocessor based relays and as a result, the bus fault clearing times were indeed longer than line fault clearing times (see **Appendix 5** for additional detail). PJM's next step was to determine if critical contingencies assumed in the AIOG were valid with the existing configuration. In short, PJM had to answer the following question: Did the new fault clearing time assumption for the various critical outages result in a more limiting condition than the previously assumed fault clearing times and critical outages already in the AIOG? If so, Salem and Hope Creek MW output could potentially be constrained more than was already specified in the AIOG.

2.2 Stability Studies and Results

Review of the existing AIOG required the examination of 18 specific critical outages. For each of these outages, PJM tested 20 different critical faults under one, two and three unit operation and both with and without power system stabilizers enabled. All simulations were conducted initially with the existing topology (i.e., without planned Artificial Island project elements in place). The analysis showed that the existing line fault with stuck breaker under a 5015 line outage remained more limiting than the bus fault with stuck breaker. In other words, the new relay clearing time information did not trigger the need for more restrictive MW output limits on Salem and Hope Creek than is already in place under the current version of the AIOG. This also indicated that PJM Operations were and had previously been secure. Bus faults and bus faults with delayed clearing were stable for the eighteen AIOG-specified system outages and consequently do not challenge the AIOG's validity.

The approved Artificial Island project had included high speed relaying utilizing optical ground wire (OPGW) communication technology, to be added to the protection systems of eight critical 500 kV circuits in the vicinity of Artificial Island, to provide additional stability margin with respect to line faults. However, given that the critical fault under the new configuration is a bus fault, the installation of the OPGW and the new line relays will not provide any appreciable stability benefit.

2.3 Transient Stability Assessment Tool Impact

In parallel, PJM planning staff conferred with operations staff to ensure that the online Transient Stability Assessment (TSA) tool used by PJM system operators in real-time was updated to ensure that a bus fault with a stuck breaker was added to the list of contingencies evaluated by the TSA tool. In real time, the TSA tool monitors and determines transient stability subject to a selected set of defined critical contingencies including bus and line faults. The TSA tool uses current, real-time system information:

- System load
- System topology & outages
- Observed system voltages
- Reactive device status
 - Capacitors, reactors, SVCs
- Machine status, MW and MVAR outputs
- Machine PSS status

This information is updated approximately every five minutes and modeled in a simulation case. In turn, the TSA system then uses the case representing the current system to compute stability limits approximately every five minutes. The TSA tool assesses the stability of the system and provides recommended stability control measures to prevent generator instability. Recommended stability control measures include providing generator-specific MW adjustment and, in some cases, MVAR adjustment as well. Implementation of the TSA tool in June 2013 provides the operators more precise stability mitigation strategies in real time for the actual system configuration than the mitigation strategies that are available from the AIOG which is based on conservative off-line planning studies.

2.4 Operational Data Supports Target Voltage Approach

PJM researched Salem and Hope Creek bus voltages over a four and one-half year period which included various local transmission outages (data charts for which are shown in **Appendix 6**). The most severe conditions were associated with six facilities:

- Hope Creek-Red Lion Line (5015)
- Salem-Orchard Line (5021)
- Keeney-Rock Springs Line (5025)
- New Freedom-East Windsor Line (5038)



- Hope Creek 2-4 circuit breaker
- Hope Creek 3-4 circuit breaker

PJM's research into Artificial Island's historical voltage levels—summarized in **Table 2**—revealed only one extraordinary occasion during which voltages exceeded 550 kV – during Hurricane Sandy in October 2012. All other data measurements fell between 525 kV and 550 kV providing strong empirical evidence that voltages in the Artificial Island area historically have remained in a relatively tight range. Voltages remained above the minimum recommended by PJM Planning under all conditions. Overall, the lowest observed voltage during an outage was 528.10 kV (1.0562 p.u.) during an outage with the Hope Creek 3-4 circuit breaker open.

Table 2 – Statistical Summary of Salem and Hope Creek Voltages

Scenario	1	2	3	4
Number of data points (hourly)	28,034	9,268	1,100	1,079
Hope Creek bus voltage (in thousands of Volts)				
Average	537.76	537.04	536.59	540.90
Maximum	548.58	551.65	559.11	547.60
+1 Std. Dev	540.49	539.99	539.99	543.38
-1 Std. Dev	535.03	534.09	533.19	538.43
Salem bus voltage				
Average	538.04	537.13	536.63	541.43
Maximum	548.85	549.70	559.60	548.34
+1 Std. Dev	540.83	540.17	540.09	543.98
-1 Std. Dev	535.24	534.10	533.17	538.88

Likewise, real-time operational data research did not identify any instances over the past four and one-half years in which Salem and Hope Creek units operated at 1.0 (unity) power factor, as summarized in **Table 3**. In other words, the AI units were always generating reactive power as opposed to absorbing reactive power. Power factors for each unit remained between 0.92 and 0.99 lagging for all outage conditions. While PJM normally assesses generator stability at 1.0 power factor, the data demonstrates that the Artificial Island units rarely operate at this level.



Table 3 – Statistical Summary of Salem and Hope Creek Power Factors
(All values are lagging unless otherwise noted)

Scenario	1	2	3	4
Number of data points (hourly)	28,034	9,268	1,100	1,079
Hope Creek Unit 1 lagging power factor (unitless quantity)				
Average	0.9744	0.9835	0.9819	0.9662
Maximum	0.9979	0.9967	0.9966	0.9929
+1 Std. Dev	0.9935	0.9933	0.9912	0.9783
-1 Std. Dev	0.9554	0.9731	0.9726	0.9541
Salem Unit 1 lagging power factor				
Average	0.9704	0.9821	N/A	0.9579
Maximum	0.9923	0.9962	N/A	0.9734
+1 Std. Dev	0.9855	1.0061	N/A	0.9635
-1 Std. Dev	0.9554	0.9582	N/A	0.9522
Salem Unit 2 lagging power factor				
Average	0.9672	0.9777	0.9856	0.9515
Maximum	0.9903	0.9956	0.9946	0.9790
+1 Std. Dev	0.9878	1.0000	0.9913	0.9588
-1 Std. Dev	0.9465	0.9554	0.9799	0.9441

3.0 Need for the New Freedom SVC

3.1 Discussion

The Artificial Island Project approved by the PJM Board included a +300/-150 MVAR Static VAR Compensation (SVC) device to be constructed by PSE&G at the New Freedom 500 kV substation. An SVC rapidly and continuously adjusts reactive power to control voltage swings under various system conditions, thereby providing additional generating unit stability margin. The ability to increase unit stability margin provided the original justification for including an SVC at New Freedom as part of the Artificial Island project.

However, the analytical data and assumptions underpinning the original justification for the SVC have changed since the PJM Board approval in July 2015. Stability studies incorporating the updated modeling information including the revised relay clearing times, the updated Salem and Hope Creek generator excitation models, the updated GSU impedance data and the updated 500/230 kV transformer impedance data noted previously suggested that the stability issues actually would be worse, given the original assumption of stability at unity power factor.

In order to mitigate the system instability, PJM staff evaluated making the SVC larger by increasing the SVC device size from +300/-150 MVAR to: a minimum of (1) +500/-150 MVAR for a termination point at Hope Creek; or (2) +450/-150 MVAR for a termination point at Salem. Installing an SVC of this size raised concerns, suggesting the need to install two smaller SVCs. While operationally preferred, such an option would further aggravate the cost of the project and would likely introduce additional siting challenges.

The larger SVC would be required to enable the units to be stable for all faults (including the worst case fault under all maintenance conditions) with the Salem and Hope Creek generators operating at unity power factor. However, the review of historical Salem and Hope Creek operational data showed that the Artificial Island units rarely operated at unity power factor (see discussion in section 2.2).

In light of review of the historical voltage data and the revised power factor and bus voltage assumptions, PJM conducted sensitivity testing to assess the behavior of the system without the proposed New Freedom SVC, with the units operating to a voltage schedule of 1.055 p.u. That assessment confirmed that the units would be stable without the SVC for all faults under all maintenance outage scenarios, provided that a minimum voltage of 1.055 p.u. is maintained, and a minimum reactive output under some maintenance conditions.

3.2 Recommendation

The SVC is not necessary to ensure unit stability provided that a minimum voltage requirement is implemented in operations. Preliminary analysis indicates a minimum voltage schedule of approximately 527.5kV (i.e. 1.055 p.u.) or higher is acceptable. Review of the historic Salem and Hope Creek substation voltage showed that Artificial Island voltages have not fallen below 528.1 kV. In addition, the use of the on-line TSA tool in operations provides operators with an indication when the units may be approaching an



unstable operating point so that corrective action can be taken. Considering all of this, PJM staff recommended that the SVC be removed from the scope of the project.

With regard to the continued use of the AIOG, the TSA tool eliminates the need for the AIOG for real time operations or outage planning, provided that the minimum voltage schedule is maintained. The TSA tool is operated in a dual-primary mode with installations at both Valley Forge and Milford, assuring high reliability and availability. However, in the rare case where the TSA tool might be unavailable or the voltage schedule is not maintained, appropriate operating procedures should be available to the operators to provide situational awareness should this unlikely situation ever be realized.



4.0 Need for OPGW

4.1 Background

As discussed above in Section 2.2, the approved Artificial Island project had included high speed relaying utilizing optical ground wire (OPGW) communication technology, to be added to the protection systems of eight critical 500 kV circuits in the vicinity of Artificial Island, to provide additional stability margin with respect to line faults.

4.2 Fault Clearing Times

PJM conducted a number of stability study simulations to test whether the addition of fiber optic technology offered any additional clearing time margin, translating into additional stability margin.

Each stability study simulation involved removing a local 500 kV transmission line from service – a “Critical Condition” in AIOG parlance. This was followed by modeling a contingency for normal fault clearing and for delayed clearing due to a stuck breaker under conventional standard three phase fault and single-line-to-ground fault tests required by NERC and PJM testing criteria.

The results showed some improvement related to line faults with the OPGW. However, that point is moot given that a *bus* fault is more limiting because of its longer clearing time, as discussed in **Appendix 5**.

4.3 Recommendation

Given that the critical fault under the new configuration is a bus fault, the installation of the OPGW and the new line relays will not provide any appreciable stability benefit. Consequently, there is no justification for retaining OPGW as part of the Artificial Island project and it is recommended to remove the OPGW from the project scope.

PJM notes that in addition to clearing time improvement, the OPGW may offer other technical benefit such as reducing “over-trip” situations. As such, PJM will continue to evaluate OPGW outside the scope of the Artificial Island project recommendation discussed.

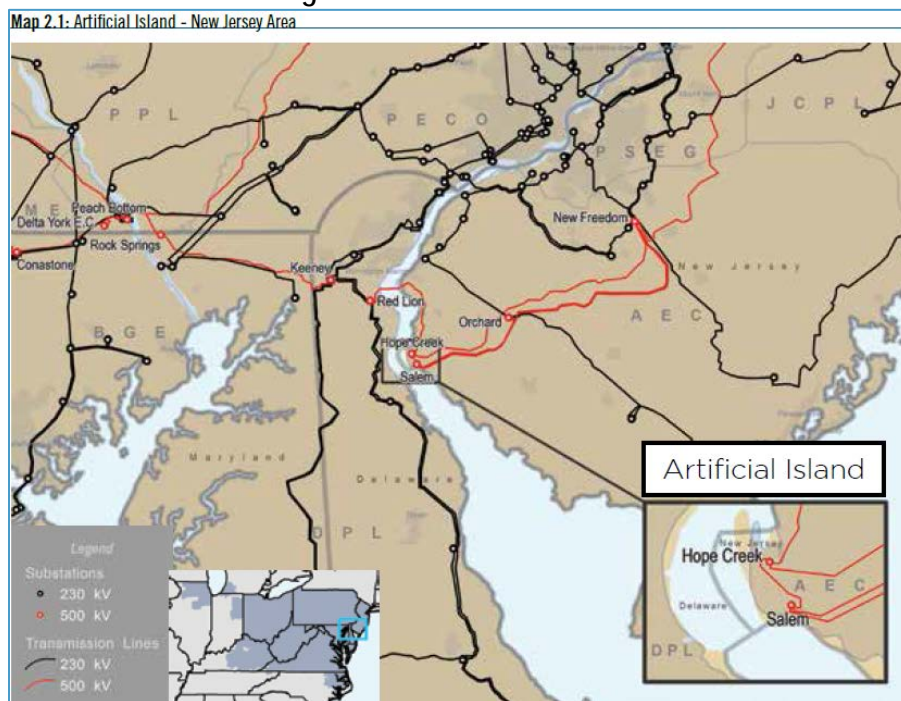
5.0 Generator Step-up Unit Tap Settings

The approved Artificial Island project included a recommendation to modify tap settings on generator step-up (GSU) transformers at Salem 1, Salem 2 and Hope Creek over the course of several future Salem and Hope Creek unit maintenance and refueling outages. PJM continues to recommend this as part of the Artificial Island project to improve local voltage profiles and improve stability margin.

Appendix 1: Artificial Island Project History

PJM opened an RTEP proposal window¹ on April 29, 2013, seeking improvements to the operational performance of 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 **Figure 2**. In its problem statement, PJM specified that proposals must improve stability margins, reduce Artificial Island MVAR output requirements and address high voltage reliability issues.

Figure 2 – Artificial Island Area



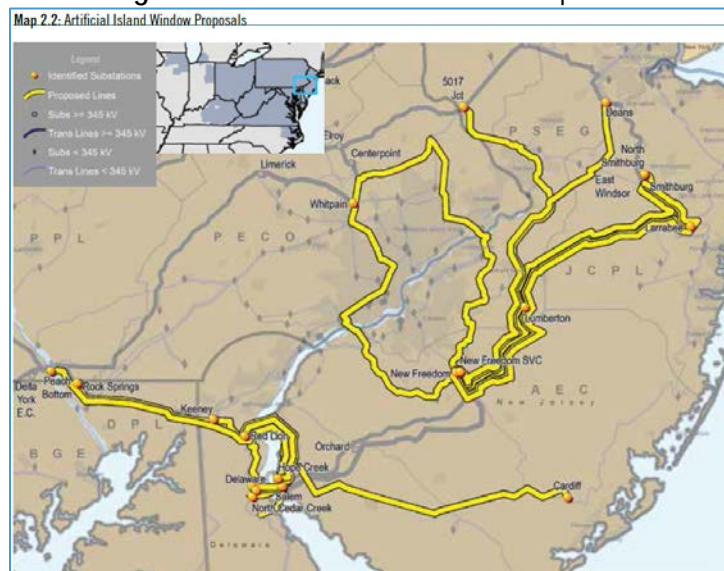
Seven different sponsors submitted 26 separate proposals, the various elements of which are listed in **Table 4** and shown on **Figure 3**, with original cost estimates (as submitted) ranging from \$100 million to \$1.55 billion. A number of proposals included identical or similar elements. Proposals reflected a diverse range of technologies: including 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.

¹ PJM notes that it sought solutions to Artificial Island's 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.

Table 4 – 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 (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 Cartanza-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 right-of-way
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 as 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 right-of-way
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 right-of-way
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-Eloy 500 kV line (5017 Junction) and Salem-Hope Creek 500 kV line	Existing right-of-way
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-Eloy-500 kV line (5017 Junction) and Salem-Hope Creek-Red Lion 500 kV lines with Hope Creek-Red Lion (new)	

Figure 3 – Artificial Island Window Proposals



Once the Artificial Island proposal 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, PJM enlisted an engineering consultant to evaluate constructability risks, such as siting and permitting, rights-of-way and land acquisition, project complexity and operational impact, among others. The results of system performance, constructability and cost evaluations allowed PJM to shortlist the following five proposals:

- 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.
- 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-Cartanza 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-Cartanza 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 for the following recommendation to the PJM Board, which was approved in July 2015:

- **Salem – Silver Run 230 kV Line** across the Delaware River, designated to Northeast Transmission Development (an affiliate of LS Power); associated substation work at Salem, including 500-230kV transformers, as designated to PSE&G; and, associated work to interconnect to the existing 230 kV lines in Delaware, designated to Pepco Holdings, Inc. (PHI)

- **300 MVAR SVC²** device to be constructed at the New Freedom 500 kV substation, designated to PSE&G
- **High speed relaying utilizing optical ground wire (OPGW) communication** technology to be added to eight critical 500 kV circuits in the vicinity of Artificial Island, designated to PSE&G, PHI and FirstEnergy accordingly.
- **Tap setting changes** to generator step-up (GSU) transformers at Salem 1, Salem 2 and Hope Creek, designated to PSE&G Power.

² Static VAR Compensation (SVC) rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.

Appendix 2: Review of the Justification for the Project

Power system stability in actual operations is affected to varying degrees a number of variables, but significantly by machine MW output, transmission system voltage, machine terminal voltage and system impedance. PJM Artificial Island stability studies over more than 25 years have identified a number of outage scenarios that would cause system instability if coupled with a corresponding set of system and machine parameters. This drove the original development of the AIOG. In light of the BRC request, the operational history of the AIOG and voltage support in the Artificial Island area was reviewed in conjunction with PJM Operations.

AIOG Experience

The AIOG, in place since 1987, specifies maximum MW output and minimum reactive power output under specified system conditions to avoid system instability.

The two most critical transmission lines for area stability are the Hope Creek-Red Lion (5015) and the New Freedom-East Windsor (5038) 500 kV lines. If either line is out of service, and all three Artificial Island units—Salem #1, Salem #2, and Hope Creek #1—are online, significant MW reduction and MVAR increases are required.

As **Figure 4** shows, when either the 5015 or 5038 line is out of service, generation output at Artificial Island has limited paths to the remainder of the PJM transmission system. Given this topology, the Salem and Hope Creek units are currently subject to both dynamic stability and transient stability restrictions. Power system stabilizers are installed on each unit to improve dynamic stability. However, if any stabilizer is out of service during three-unit operation, unit reductions and/or increases in MVAR output are necessary.

Figure 4 – Artificial Island Area 500kV Single Line Schematic Diagram

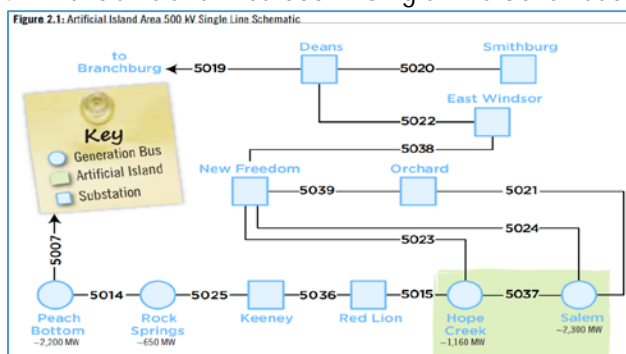


Figure 5 shows the 338 instances between 2000 and 2016 when the AIOG was invoked during a scheduled or forced outage of any of the 500 kV transmission lines, listed in **Table 5**. The AIOG provides system operators guidance for unit operation under outage conditions for each of the lines listed.

Figure 5 – Artificial Island Historical Transmission Line Outages

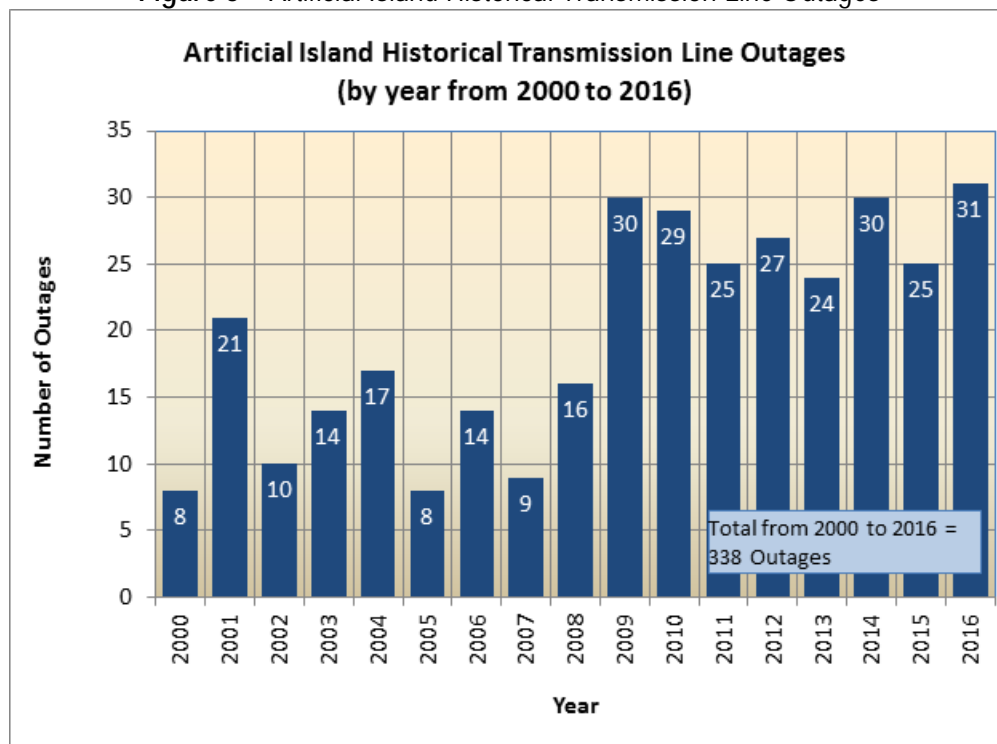


Table 5 – Artificial Island Area 500 kV Line Outages Requiring AIOG Action

Branchburg-Deans (5019) 500 kV	Keeney-Red Lion (5036) 500 kV
Deans-East Windsor (5022) 500 kV	Keeney-Rock Springs (5025) 500 kV
East Windsor-New Freedom (5038) 500 kV	New Freedom-Orchard (5039) 500 kV
Hope Creek-New Freedom (5023) 500 kV	New Freedom-Salem (5024) 500 kV
Hope Creek-Red Lion (5015) 500 kV	Orchard-Salem (5021) 500 kV
Hope Creek-Salem (5037) 500 kV	Peach Bottom-Rock Springs (5014) 500 kV

If either the Hope Creek-Red Lion line (5015) or the New Freedom-East Windsor line (5038) is forced out of service, Artificial Island total output must be reduced immediately.

- 5015 line outage: 900 MW total reduction from 3,818 MW to 2,900 MW
- 5038 line outage: 600 MW total reduction from 3,818 MW to 3,200 MW

Other prevailing system conditions – particularly under peak load conditions when the system is stressed – can require additional operator action to preserve reliability. For example, a forced outage of the 5015 or

5038 line during the January 7, 2014 capacity shortage Polar Vortex conditions would have likely required additional PJM emergency procedures including Voltage Reduction and Manual Load Dump Action³.

Scheduling Transmission Maintenance

Scheduling transmission maintenance presents its own set of issues. Primarily due to operational performance, only thirteen of the 30 (43%) Hope Creek – Red Lion (5015) 500kV scheduled line outages between 2010 and 2016 have been successfully completed. The remaining 17 outages (57%) were cancelled by the Transmission Owner, Generation Owner, denied by PJM or returned to service early to address voltages in excess of acceptable limits at Artificial Island busses. Such outage cancellations have temporarily delayed transmission owner capital budget work until the outages could be rescheduled during more favorable operating conditions. Examples of outages that have had to be rescheduled include, Hope Creek 500 kV breaker replacements, sub-transmission and distribution upgrades for facilities sharing the same right-of-way with the 5015 and 5038 transmission lines, and required NERC relay testing. Outage windows generally need to be scheduled during a Salem or Hope Creek unit outage or reduction. The difficulty of scheduling planned outages on these facilities underscores the challenges system operators have in managing system voltages following unplanned forced outages.

Thirteen of the 17 (77%) East Windsor – New Freedom (5038) 500 kV line outages scheduled between 2010 and 2016 have been successfully completed. The remaining four outages (23%) were cancelled by the Transmission Owner or denied by PJM to control high voltage issues at the Artificial Island units.

System Topology Changes

Since implementation of the AIOG in 1987, numerous system topology changes and other key modeling parameters have precipitated eleven Artificial Island Operating Guide revisions, including capacity up-rates totaling 381 MW at Salem and Hope Creek. Also, since 1997, PJM-identified baseline upgrades, network upgrades and transmission owner supplemental bulk electric system (BES) enhancements have been added in the area. For example, two additional 230 kV circuits between Camden and Gloucester, a second Mickleton-Gloucester 230 kV line and a second Cox's Corner-Lumberton 230 kV line, all within electrical proximity, have been placed in service.

PJM has experienced higher than normal voltage profiles as a result of those changes. While higher voltage is generally advantageous, facility voltage upper limits can also present operators with reliability concerns, typically during overnight, or “valley,” periods when transmission lines are more lightly loaded.

Artificial Island Project Requirements Document

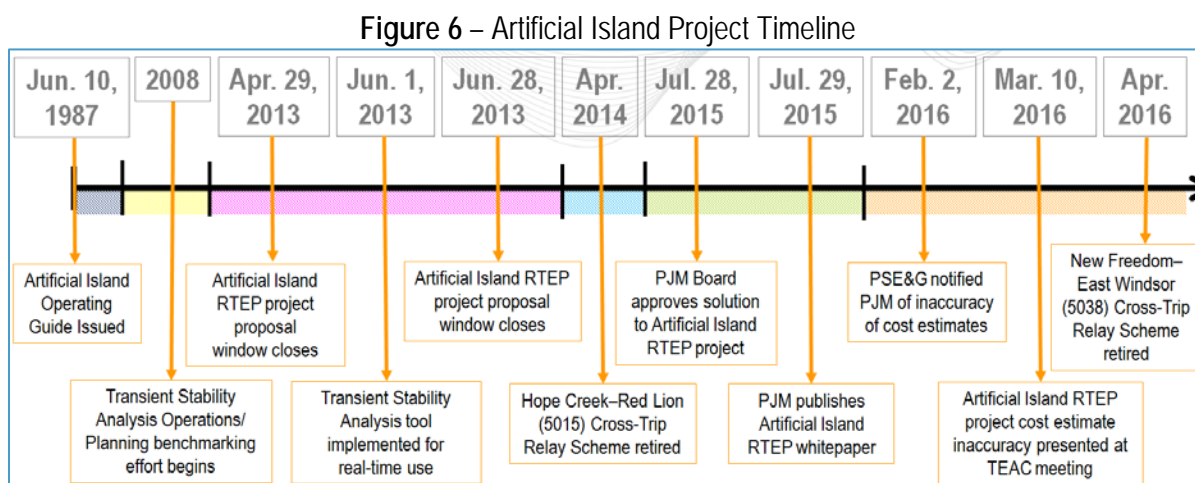
In light of the need to provide additional operational flexibility, PJM's April 29, 2013 Proposal Window Problem Statement and Requirements document⁴ requested that proposals achieve the following objectives:

³ These operator actions are described in PJM Manual 13, “Emergency Operations:”
<http://www.pjm.com/~media/documents/manuals/m13.ashx>

⁴ The requirements document can be found on PJM's web site: <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/~media/planning/rtep-dev/expansion-plan-process/ferc-order-1000/rtep-proposal-windows/redacted-artificial-island-problem-statement.ashx>

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 (PSS) of Salem Unit 2 and Hope Creek. The Salem Unit 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)

Opening a window to address the issues included in the Requirements Document was another milestone in an unfolding Artificial Island timeline, shown in **Figure 6**.



Risks Associated with Continuing to Operate with the AIOG

Operations of the Artificial Island generation units have proceeded for a long time under the requirements of the AIOG. The problems associated with operating in this mode are documented above. It is conceivable to continue to operate indefinitely under the requirements of the AIOG and forego the Artificial Island project. The periodic reductions of energy output and difficulty of undertaking maintenance are well understood and the impacts are mainly economic.

The most significant risk of continuing to operate in the current mode is the potential reliability issues that would ensue in real time from a multiple unit trip at Artificial Island. PJM maintains a number of transfer limits for west to east flows across the PJM transmission system, classified as Interconnection Reliability Operating Limits (IROLs). Exceeding IROLs can cause cascading and widespread outages. In order to

mitigate those risks, PJM is required to implement all emergency procedures, including load dump, correcting IROL violations within 30 minutes. Failure to correct within the 30 minute timeframe would extend the period that the system is in a vulnerable state and is a standard violation which requires an immediate self-report to NERC.

Just as Artificial Island unit reductions are necessary for some planned outage scenarios, unit reductions, including scrambling a nuclear unit off-line, may become necessary in real time if critical unplanned 500kV outages occur.

Assessing the potential impacts of a multiple unit trip at Artificial Island is a scenario that PJM Operations studies on a continuing basis. In the semi-annual Operations Analysis Task Force (OATF) study, the loss of Artificial Island generation is assessed. While the most recent versions of the OATF study show that the simultaneous loss of the Artificial Island generation is survivable, there are other factors in operations that support the proposed 230 kV project, namely:

1. **Additional 500/230kV path:** The new Hope Creek 500/230 kV transformer provides a more direct path to Hope Creek / Salem 500kV in order to provide safe shutdown to nuclear generation during restoration scenario.
2. **Constructability:** 500kV option would require extended outages of the 5015 500kV line during the spring/fall timeframe which would impact 500kV voltages and restrict Salem/Hope Creek nuclear generation.
3. **Resilience:** Adding an additional 230kV path provides increased resilience as opposed to exposing the system to a new double-tower 500kV contingency, which would result in the same stability concerns under an outage condition. The Hope Creek 500/230kV transformer also provides additional resilience during restoration.

Appendix 3: Cost Estimation Review

PJM's comprehensive analysis included an assessment of cost estimates that focused on five main areas:

- The reconciliation of the original PJM cost estimate compared to the drivers for PSE&G's estimate based on review of site conditions (Salem 500 kV connection, New Freedom SVC and OPGW).
- Costs comparisons for two Hope Creek alternatives (4a and 2b)
- Confidence level in the cost estimates and associated cost capping provisions received from PSE&G
- The impact of the PSE&G cost estimates on all of the finalist projects
- A comparison between the cost estimates of the PSE&G 7K Red Lion to Hope Creek 500kV line and the LS Power 5A Hope Creek to Silver Run 230kV line removing the OPGW relay upgrades and the New Freedom SVC.

The Artificial Island project ultimately selected, shown earlier on **Figure 1**, included the following major elements:

- Salem – Silver Run 230 kV Line across the Delaware River, designated to Northeast Transmission Development (an affiliate of LS Power); associated substation work at Salem, as designated to PSE&G; and, associated work to interconnect to the existing 230 kV lines in Delaware, designated to Pepco Holdings, Inc. (PHI)
- A new 300 MVAR SVC device to be constructed at the New Freedom 500 kV substation, designated to PSE&G
- High speed relaying utilizing fiber optic communications installed in OPGW, added to the protection systems of eight critical 500 kV circuits in the vicinity of Artificial Island, designated to PSE&G, PHI and FirstEnergy accordingly
- Tap setting changes to generator step-up transformers at Salem 1, Salem 2 and Hope Creek, designated to PSE&G.

A summary of the RTEP process that led to PJM's July 2015 Artificial Island recommendation to the Board is included in **Appendix 1**.

February 2, 2016 PSE&G Cost Estimates

Following July 2015 project approval by the PJM Board, PSE&G notified PJM that the cost estimate for their work at Salem, New Freedom and on the high speed relaying, was significantly greater than the estimates that were developed by PJM staff and were part of the basis for the recommendation to the Board. **Table 6** provides a comparison of the PJM Board-approved Artificial Island project component cost estimates designated to PSE&G and the cost estimates that were submitted by PSE&G in early 2016.

Transmission project cost estimates are influenced by many factors, including line routing, siting and permitting, environmental remediation, engineering, material procurement, line construction, expansion of existing substations, project management and contingency. PJM's cost estimate was based on conceptual level information. Where possible, PJM used per-unit costs from similar projects. PJM enlisted the assistance of third party consultant expertise to assess the validity of the submitted cost estimates submitted with the proposal and additional cost estimates development by PJM where required because no cost estimates were provided by the Proposing Entity.

PJM developed total estimates that coupled (1) the proposing entity's cost commitment numbers with (2) PJM-developed estimates to be assigned to the incumbent transmission owner — including expansion of existing substations, cut-ins to existing lines, addition of fiber optic wire to existing lines and the addition of an SVC. As a result, the \$275.5 million project solution that was approved by the PJM Board included the PSE&G components totaling \$137 million, shown in **Table 6**.

Prior to designation of the project, PSE&G did not perform physical site investigations or detailed design work for the upgrade portion of the work. Many identified issues – upgrading the drainage system, relocating structures, addressing expanded relay control systems – could not have been identified fully without more detailed investigation.

Table 6 – Artificial Island Project PSE&G Component Cost Estimate Comparison

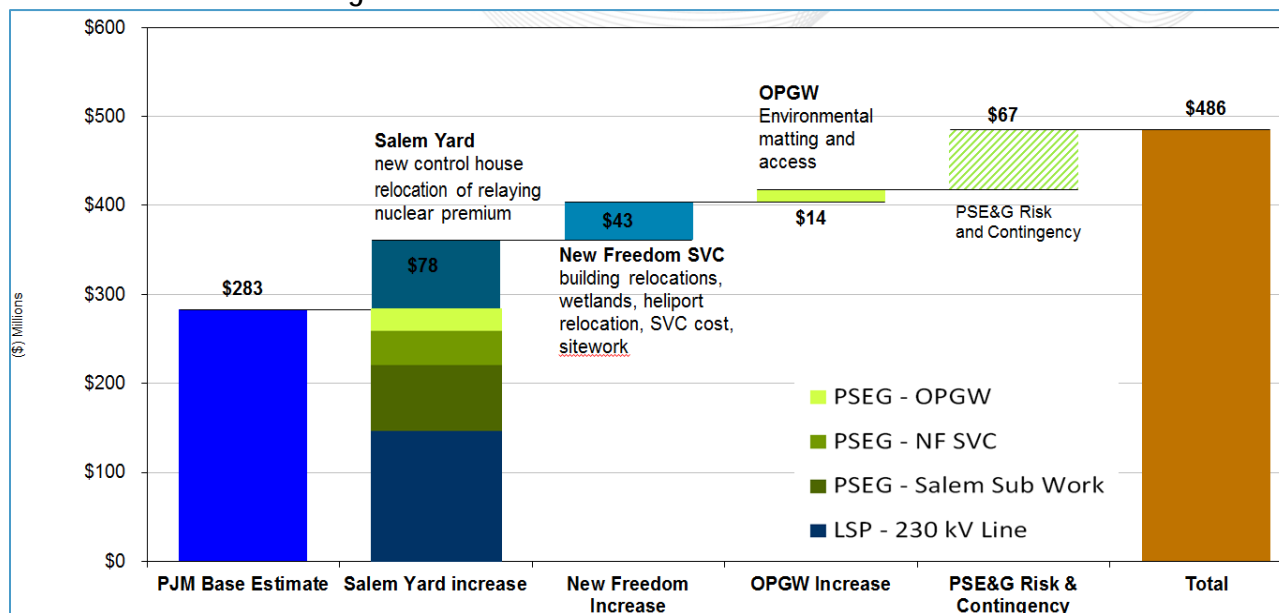
RTEP Project PSE&G Components	Board-approved Project Estimate (\$, Million)	PSE&G Post Board Approval Estimate* (\$, Million)	Difference (\$, Million)
New Freedom SVC	\$38	\$81.1	+\$43
High Speed Relaying	\$25	\$39	+\$14
Salem Station Expansion	\$74	\$152.2	+\$78
TOTAL	\$137	\$272.3	+\$135.3

*PSE&G risk and contingency (R&C) is not included. R&C is an additional 25%.

Reconciliation of PSE&G and PJM Cost Estimates

PJM reviewed the original estimates for each portion of PSE&G work associated with the Artificial Island project. PJM also consulted with PSE&G to determine what adjustments were warranted to reconcile the differences between the PJM and PSE&G estimates. The main categories of the differences are illustrated in the **Figure 7** waterfall diagram.

Figure 7 – PJM and PSE&G Estimate Reconciliation



Following several discussions between PJM and PSE&G to review and understand estimate drivers, PJM found that there were multiple factors that contributed to the difference between the PJM and PSE&G cost estimates, as presented at the March 10, 2016 TEAC meeting.

Transmission Line Alternatives

PJM conducted discussions with PSE&G and LS Power and identified several viable line and substation location alternatives. Initially, PJM considered six options two of which were identified that met required electrical performance and appeared to mitigate some of the items driving PSE&G’s February 2, 2016 cost estimate increase. The two alternatives would terminate the new 230 kV Silver Run line into the Hope Creek substation instead of Salem.

The first option would include the construction of a new 500/230 kV yard in marshland located to the north of the existing Hope Creek substation and the expansion of the existing 500kV yard to accommodate a new bay. This was designated as option 4B. Option 2B expands the existing Hope Creek substation to the north constructing a bay to accommodate the new 500/230 kV transformer and 230kV line termination. After further analysis, the high cost of site preparation for option 4B was determined to make it less desirable than option 2B.

Option 2B

The Option 2B Hope Creek interconnection via expansion would include the following tasks:

- Expand the existing Hope Creek substation to accommodate the new bay, transformer and 230kV termination
- Route the new 230 kV submarine cable from Delaware an additional 3,000 ft. (approximately) to the new expansion site

The expansion site is physically constrained and will have a significant impact on the existing Hope Creek substation. PSE&G's cost estimate for this scope of work is \$132 million, including PSE&G risk and contingency.

Submarine Cable

The change in route for the 230 kV submarine cable for options 2B or 4A will require a different cable alignment for about 10,000 ft. across the Delaware River, resulting in a slightly shorter river crossing length. The change will add approximately 3,000 ft. of 230 kV transmission line on the New Jersey side of the river requiring increased coordination with the Artificial Island facility on design and property rights compared to a Salem interconnection.

LS Power expects there will be incremental cost increase, but the expected cost is still estimated to be under the current cost commitment. LS Power has stated that it will not cap right-of-way costs associated with PSE&G nuclear property.

Project Cost Estimate Summary of Alternatives

Numerous discussions with PSE&G over ten months ultimately yielded the cost estimates summarized in **Table 1**.

Approved Artificial Island Project Estimate and Timing Confidence

LS Power completed a significant portion of the project preliminary engineering and river survey work prior to the August 2016 suspension. \$6.4 million was spent on development in the following areas:

- Executed a fixed price engineering, procurement and construction agreement for both the cable, material and installation
- Pre-application meetings held with most permitting agencies
- All private real estate rights in Delaware secured
- Silver Run substation design complete for permitting
- Permitting level designs completed for submarine and aerial river crossings and six overland routes to support US Army Corps of Engineers alternatives analysis

Based on the current status of the LS Power project work completed prior to the suspension, there is increased certainty in the current cost estimate of \$133 million. LS Power's cost containment cap is currently \$146 million.

Cost Comparison between PSE&G 7K and the LS Power 5A Projects

The comparison of the current cost estimates for the LS Power 5A and PSE&G 7K project removing the OPGW relay upgrades and the New Freedom SVC are below in **Table 7** and **Table 8**.

Table 7 – PSE&G 7K Cost Estimate with Recommended Scope

Project Components (costs in millions)	PSE&G 7K Red Lion to Hope Creek
500kV Line and Hope Creek Expansion (PSE&G)	\$221
Red Lion Expansion (PHI)	\$33
Project Total	\$254

Table 8 – LS Power 5A Cost Estimate with Recommended Scope

Project Components (costs in millions)	Current Recommended Artificial Island Project
230kV Line and Silver Run Substation (LSP)	\$133
Hope Creek 2B Interconnection (PSE&G)	\$104
PSE&G Contingency	\$28
DE Interconnection (PHI)	\$2
Project Total	\$267

In directly comparing the current cost estimates, the costs that have been incurred to date by the approved project should be taken into consideration. LS Power has incurred costs that stand at approximately \$6.4 million.

The cost difference between the two projects, given the above, is \$7 million, which is approximately a 3% increase from the PSE&G 7K to the LS Power 5A project.

Appendix 4: Constructability Review

4.1 Constructability Review Summary

PJM reviewed the component elements of the original five finalist proposals out of which the final July 2015 Artificial Island project recommendation was developed:

- *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.
- *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.
- *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-Cartanza 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-Cartanza 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 (TCSC) devices in each line.

Based on additional technical and constructability evaluation, PJM was able to assign the five finalists to one of the following three categories – as of August 2014 – for additional, more detailed assessment.

- TCSC Project
 - Dominion 1A
- Parallel 500kV Line Hope Creek to Red Lion
 - Dominion 1C
 - Portion of PSE&G 7K
- Southern Crossing 230kV Lines
 - Transource 2B
 - LS Power 5A

That additional detailed assessment evaluated the considerations summarized in **Figure 8**.

Figure 8 – Proposal Evaluation Considerations

Primary Considerations				
Technical Analysis		Cost Factors		
<ul style="list-style-type: none"> Thermal Stability Short-circuit 	<ul style="list-style-type: none"> Voltage NERC Cat-D Contingencies 	<ul style="list-style-type: none"> Cost commitments Cost effectiveness Market efficiency PJM estimated costs 		
Secondary Considerations				
Schedule	Project Complexity	Right of Way and Land Acquisition	Siting and Permitting	Operational Impact
<ul style="list-style-type: none"> Permitting Construction Long lead time equipment 	<ul style="list-style-type: none"> Line crossings Outage requirements Modifications to Red Lion substation Modification to Artificial Island substations Modifications to other transmission facilities 	<ul style="list-style-type: none"> New right of way required Substation land required 	<ul style="list-style-type: none"> Wetlands impact Public opposition risk Delaware river crossing Land permitting Historic and scenic highway 	<ul style="list-style-type: none"> Artificial island facility requirements Ongoing maintenance Black-start Route diversity Operational flexibility

4.2 Constructability Impacts

TCSC Project

Initial evaluation revealed that potential sub-synchronous resonance (SSR) and transient stability issues associated with the SVC and TCSC technology elements of proposal DVP-1A were such that PJM removed it from additional consideration. Additional analytical work, constructability evaluation and stakeholder discussions of the remaining four finalist proposals guided PJM's development of the Artificial Island solution approved by the Board in July 2015. Those factors have not changed during the interim and remained part of staff's comprehensive review for the Board.

Parallel Red Lion – Hope Creek (5015) line

PJM evaluated these two options prior to July 2015. At that time, PJM identified constructability issues which resulted in their removal from additional consideration. Since that time, PSE&G met with PJM and outlined an alternative route for the Red Lion-Hope Creek line that would avoid the Supawna National Wildlife Refuge. The alternative route would lengthen the line by approximately 1.5 miles and require the acquisition of approximately 6 miles of new private right-of-way. The alternative route could partially mitigate the difficulties associated with obtaining permits, but the cost and schedule impacts are unknown. Additionally, the new route would open the PSE&G cost commitment to escalation given the exclusion language provided to PJM. PSE&G has maintained that the original path through the Supawna National Wildlife Refuge is the preferred route, but given the above, there appears to be a potential of the cost commitment being opened to increased costs.

Southern Crossing 230kV Lines

Constructability issues that were evaluated as part of the original Artificial Island window proposals have not changed subsequent to July 2015 Board approval. Several key observations emerged that guided ultimate selection of the Artificial Island project elements over the others under consideration, including those of the four finalists:

- 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. 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 or equivalent submarine installation to minimize environmental impacts.
- The new Hope Creek 500/230 kV transformer provides a more direct path to the Hope Creek and Salem 500kV substations in order to provide an additional safe shutdown feed to the nuclear generation facility during a restoration scenario.
- The additional 230kV path provides increased resilience as opposed to exposing the system to a new double-tower 500kV contingency, which would result in the same stability concerns under an outage condition.
- The 230kV southern transmission line proposals have little to no outage impact to the 5015 line between Red Lion and Hope Creek substations. Outages of the 5015 500kV line in the spring/fall timeframe would impact 500kV voltages and restrict Salem and Hope Creek nuclear generation.

Overall, PJM concluded that Hope Creek Option 2B is the preferred point of interconnection, mitigating constructability concerns associated with the Salem interconnection in the original July 2015 approved project. The concern about the Salem interconnection has to do with the fact that the existing protection devices are contained in the Salem reactor building and consequently subject to the nuclear design requirements associated with seismic mitigation, fire protection, etc. Installation of additional protection equipment inside the Salem reactor building would be very costly and subject to the nuclear procedures that all plant modifications must undergo. Relocation of that equipment to the Salem switchyard would entail the construction of a new control building for the switchyard and other associated costs. In either case, the Salem interconnection is very costly relative to the Hope Creek interconnection, which is primarily confined to the Hope Creek switchyard.

PJM engaged a consultant to review the permitting findings contained in the initial permitting analysis report prepared in October, 2014 in order to ensure that the regulatory landscape and resultant findings were still valid. The investigation confirmed that the summary of permits required was still valid and the overall findings regarding risk were still appropriate. The consultant identified the potential for application of the

recently enacted FAST Act, which may be suitable for the Artificial Island project given the types of federal permits required and the magnitude of the project, but noted that the regulations are intended for expediting review while not changing any of the underlying requirements or likely outcome.

Several key strengths and weaknesses for proposals are summarized in **Figure 11**. The relocation of the 230kV line attachment into the Artificial Island complex from Salem to the Hope Creek substation is highlighted in Figure 9

Figure 11 – Finalist Project Evaluation Factors Comparison

Project Type	Strengths	Weaknesses
500kV Line Hope Creek to Red Lion	<ul style="list-style-type: none"> - Hope Creek expansion considered more constructible than Salem expansion - Greater transfer capacity 	<ul style="list-style-type: none"> - Permitting through Supawna Meadows National Wildlife Refuge - Permitting through state wildlife management areas - River crossing permitting - Potential view-shed impacts - 5015 line outage requirements
Southern Crossing 230kV Lines	<ul style="list-style-type: none"> - Submarine cable installation technology removes potential view-shed issue and lowers risk for a NEPA EIS being required - Cost containment provisions provide greater cost certainty - Resilient alternative path (black start and route diversity) - Hope Creek expansion considered more constructible than Salem expansion 	<ul style="list-style-type: none"> - Salem is constrained with limited space for expansion - River crossing permitting - Permitting through state wildlife management areas

Note: Red text indicates project factors that changed due to the relocation of the termination point from Salem to Hope Creek

Appendix 5: Protection and Control Review

Subsequent to July 2015 PJM Board approval of the Artificial Island project, PSE&G informed PJM that they discovered information that changed a key critical clearing time assumption associated with the protection and control schemes in place at Salem and Hope Creek. PSE&G indicated that they had upgraded certain relay technology such that the clearing time for a bus fault with a stuck breaker was now longer than a line fault with a stuck breaker, meaning that the clearing time used in the evaluation of the Artificial Island proposals was incorrect.

PJM recognized that this had potential implications for existing AIOG practices, as well as the scope of the Artificial Island project:

1. The validity of the existing AIOG based on assumed limiting contingencies was called into question, i.e. was PJM operating in an unstudied state?
2. The need for OPGW communications and the SVC had to be reassessed to determine whether either or both could be minimized or removed from the project's scope?

PJM's comprehensive review sought to examine and understand explanations by PSE&G regarding the counterintuitive assertion that bus clearing times are longer than the line clearing times. PJM's own research into relay technology and discussions with PSE&G engineering staff revealed that bus clearing times at Salem were longer than clearing times for transmission lines around Artificial Island.

Validating AIOG Assumptions

In order to understand the nature of PJM's concerns, a few basics regarding the timing of protection devices included in relay schemes here. Timing for a fault with normal clearing (i.e., without a stuck breaker) is calculated as:

Normal Clearing Time = Relay Operate Time + Auxiliary Relay Operate Time + Breaker Interrupting Time

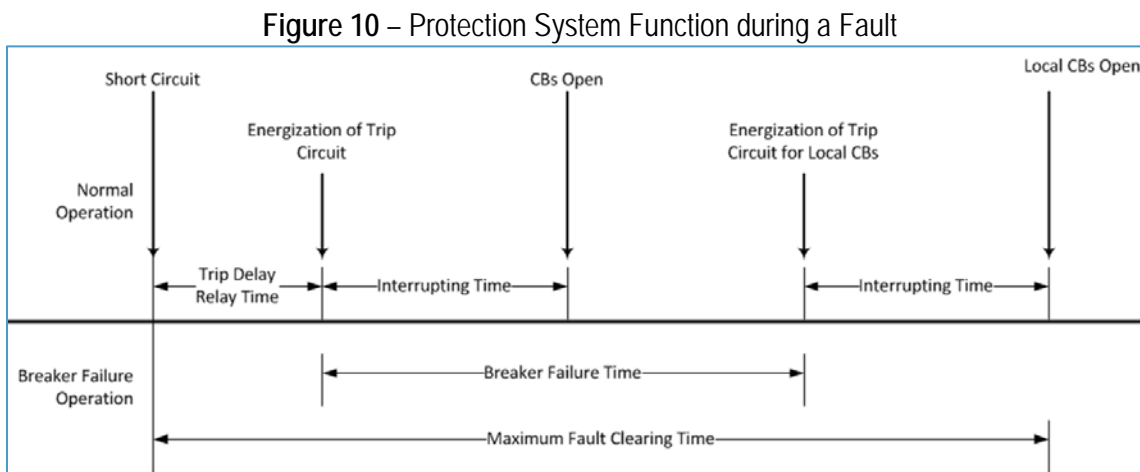
- *Relay Operate Time* refers to the amount of time it takes for a relay to determine that a fault exists.
- *Auxiliary Relay Operate Time* refers the energization of the circuit breaker's trip coil.
- *Breaker Interrupting Time* is the amount of time that the breaker takes to physically extinguish the electric arc through mechanical means, thereby clearing the fault. Breakers on PJM's 500 kV transmission system typically interrupt within 2 cycles.

Timing for a *fault with a stuck breaker* is calculated as:

*Delayed Clearing Time (with stuck breaker) = Relay Operate Time + Breaker Failure Timer
+ Auxiliary Relay Operate Time + Breaker Interrupting Time*

This equation includes breaker failure timing which is chosen to delay the breaker failure scheme. The delay is chosen based on coordinating the breaker failure scheme with the other protection systems in

place to prevent an over-tripping event. Industry practice is a 6 cycle delay at 500 kV or a slightly faster 4.5 cycles if the substation is electrically close to a large generator. Importantly, breaker interrupting time and auxiliary relay timing are fixed based on the nature of the device. The only part of the equation that can vary is relay operate time. **Figure 10** shows a visual representation of how the protection systems function during a fault.



PJM's own research together with a number of PSE&G discussions revealed that microprocessor relays with modern high-speed communications equipment have extremely fast pickup times that rival or even exceed bus differential relays. The gradual conversion of electromechanical line protection schemes utilizing Power Line Carrier (PLC) to microprocessor relays using high-speed fiber for communication along with direct breaker tripping is reducing overall clearing times – shown in **Table 9** – for transmission line faults while improving security against misoperation.

Table 9 – Operating Times of Distance Elements for Various Distance Relay Types

Line Protection Distance Relay Technology	Typical Operating Time (cycles)
Electromechanical relay	2.75
Solid-state relay	2.25
Microprocessor relay	1.75
Hi-speed Microprocessor relay (e.g. SEL-421)	0.8

Relay Technology Evolution

Traditional transmission bus protection schemes have maintained their security throughout this transition to microprocessor relays. The use of high-impedance differential schemes for protection of high-voltage buses has been the application of choice for many utilities in the United States. High-impedance bus differential relays are relatively straightforward to develop settings for and have an excellent performance

record. They also facilitate future bus expansion as they do not require current transformer (CT⁵) inputs for all breaker positions on the bus; CTs can be ganged together at a common point in the substation yard and require that only one set of leads are brought into the control house. The nominal fault detection time for this type of relay, also called relay operate time, is 1-1.5 cycles (16.7-25 milliseconds). An auxiliary relay is normally used in conjunction with the high-impedance bus differential relay and can add up to one additional cycle to the overall clearing time.

Microprocessor-based relays also take advantage of additional internal hardware and programmable capability that do not exist in older technologies. In traditional electromechanical schemes, the primary relay closes a contact that energizes an auxiliary relay. This auxiliary relay then trips associated circuit breakers and typically initiates other protection functions such as automatic reclosing and breaker failure schemes. The auxiliary relay and logic outside of the primary relay adds additional time to the overall operation of the scheme. Microprocessor relays exploit high computational internal clock timing and programmable logic capabilities to accomplish the other protection functions and in addition have output contacts capable of direct tripping associated circuit breakers eliminating the need for the auxiliary relay resulting in improved clearing times of the protection scheme.

Conclusion

Based on this evaluation, PJM was able to conclude that a bus fault with delayed clearing (stuck breaker) was now longer than a line fault with stuck breaker. Consequently, faster relaying on the 500kV transmission lines to support the Artificial Island project was no longer needed.

⁵ A current transformer is a device intended to facilitate measurement of large currents.

Appendix 6: Data Charts from the Operational Data Review

Below are detailed data charts (Figures 11-14) from the operational data review that support the analysis explained in Section 2.4 above

Figure 11 – Historical Salem Voltages during Selected Outages

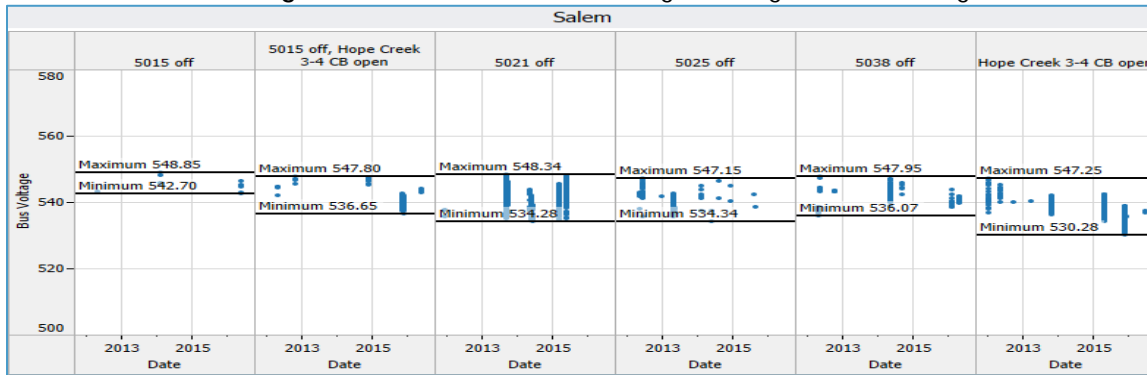


Figure 12 – Historical Hope Creek Voltages during Selected Outages

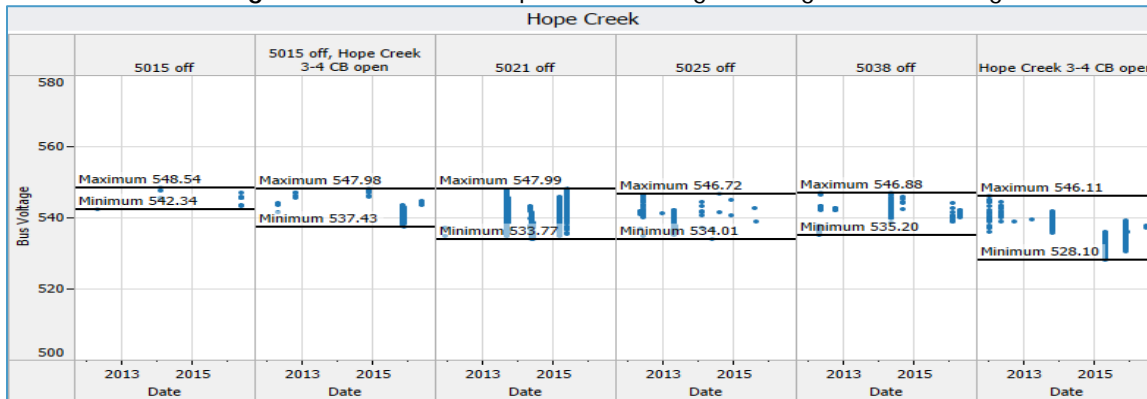


Figure 13 – Salem Unit 1 Power Factors during Selected Outages

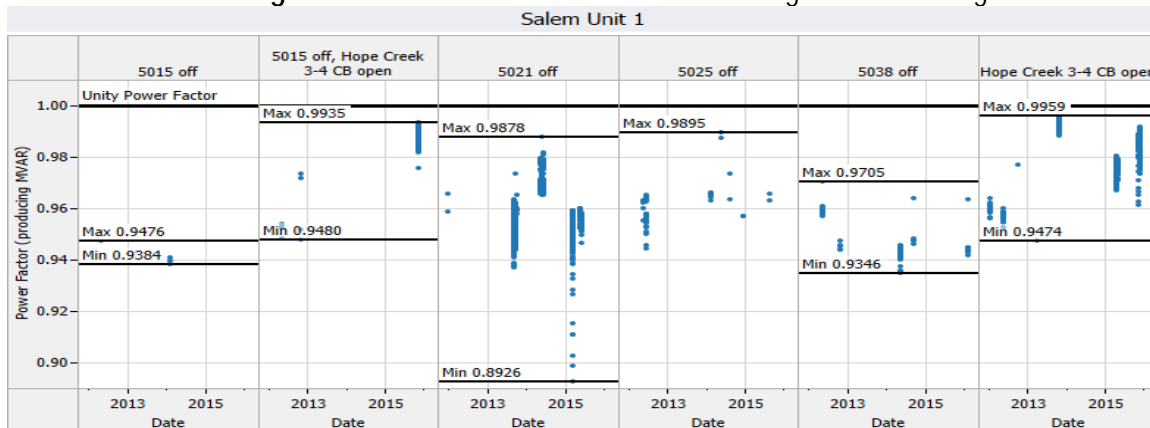


Figure 14 – Hope Creek Power Factors during Selected Outages

