Alternative Approaches to Identification of Artificial Island Project Beneficiaries

Revision 1

June 29, 2017

~~June 9, 2017~~

Revision 1

PJM provides this revised white paper to address several specific issues raised by PJM stakeholders at the June 9, 2017, special Transmission Expansion Advisory Committee meeting. The revision history at the end of this document contains the changes made since the original June 9, 2017 version.

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1. Introduction

Upon completion of its requested comprehensive review, the PJM Interconnection Board of Managers approved, in April 2017, lifting the suspension of the Artificial Island project. The board's April 2017 decision re-affirmed its prior conclusion that a transmission upgrade at the Artificial Island generation complex in southern New Jersey would effectively and efficiently resolve operational performance issues and improve stability on the transmission system around the Artificial Island generation complex. The project ultimately chosen by the board after a public competitive solicitation calls for construction of a 230-kilovolt transmission line under the Delaware River, connecting a substation at one of the nuclear stations to a new substation to be built in Delaware. Although not a part of the board's process of determining the most cost-effective and efficient solution to stability issues at Artificial Island, the board also directed PJM to provide information to states and stakeholders that they could consider in addressing issues concerning cost allocation of the project. Specifically, since cost allocation disputes often center on identification of the "beneficiaries" of a given project, the board asked PJM staff to outline potential means to identify beneficiaries of projects performed for stability reasons that could be considered in addition to the strict application of solution-based DFAX. The board's call for exploring alternatives was in response to concerns expressed by legislators, consumer advocates and other stakeholders regarding cost allocation of the $280 million project and in recognition that, unlike most thermal-driven projects, there are a number of different ways to identify the beneficiaries of a stability-based project such as Artificial Island.

In a letter to stakeholders and government officials in Delaware and New Jersey, PJM CEO and President Andrew Ott said that, although a solution-based power flow formula (the current distribution factor method, or "DFAX") works fairly and reasonably to identify project beneficiaries for the majority of lower-voltage transmission projects, it can result in anomalous results in cases where the engineering rationale or need for the particular project is not driven by power flows. "Indeed, PJM has suggested that the Artificial Island project is unique in nature and that application of the DFAX methodology to a stability or short-circuit problem may not yield clear beneficiaries," the letter said.

PJM does not have the authority to devise or file allocation methodologies as federal law makes clear that the section 205 filing rights over rates and cost allocation in this area rests with the PJM transmission owners. This paper is the response to PJM's commitment to provide information and ideas that will aid transmission owners, the states and other stakeholders should they chose to seek Federal Energy Regulatory Commission approval for an alternative cost allocation proposal for stability projects such as Artificial Island.

Guiding Principles from FERC Precedent

FERC Order 1000 required that regional cost allocation methods for new or upgraded transmission facilities included in a regional transmission expansion plan (RTEP) be allocated in a manner that is "roughly commensurate" with the benefits received by those who will pay the costs. Following issuance of Order 1000, the FERC-accepted regional cost allocation methodology for RTEP projects needed to address reliability issues was a flow-based methodology that identified the load zones that contributed to the loading on the new or upgraded facility. The flow-based approach works fairly and reasonably to identify project beneficiaries in the vast majority of projects involving thermal and voltage reliability criteria. In some instances, however, where a particular project is not needed to address thermal or voltage reliability criteria, the results of the cost allocation methodology may produce a perceived gap between the allocation of costs and the benefits. For example, the cost allocations for the Artificial Island project, which is being driven by a stability issue, may raise issues as to whether the costs of the project are fairly allocated to all of the appropriate beneficiaries of the project. As applied to the Artificial Island project, 93 percent of the cost is allocated to the Delmarva Power region. It should be noted that the Artificial Island project is the largest scope generator stability driven project since the 2000 inception of PJM's Regional Transmission Expansion Plan; therefore, there is no precedent for using a different method to identify and measure beneficiaries.

In order to explore the potential for alternative cost allocation methods for stability driven projects, PJM planners considered a broad range of approaches to measuring the beneficiaries of stability solutions. Of those studied, two alternative cost allocation methods emerged that may be reasonable to apply to upgrades that address stability. They are described in this paper. The examples associated with the two alternative stability based allocation methodologies are provided merely to facilitate discussion. The numbers in the examples should not be interpreted as final allocation percentages.

2. Current Method of Beneficiary Identification

Under FERC Order 1000, each transmission provider was required to include its Order 1000-compliant rate design in its Open Access Transmission Tariff. In PJM, the transmission owners have taken the position – based on the Atlantic City v. FERC settlement agreement – that they have the exclusive, unilateral Section 205 filing rights regarding recovery of transmission revenue requirements and the transmission rate design. The terms of the settlement regarding the parties' (including PJM's) Section 205 filing rights were updated in the PJM Tariff and the PJM Consolidated Transmission Owners Agreement (CTOA) with the proviso that Section 205 filings to change the regional rate design may only be made by the parties acting collectively in accordance with Section 8.5.1 of the CTOA. Based on such rights, the PJM transmission owners developed and proposed a consensus cost allocation methodology to comply with the six regional cost allocation principles established in Order 1000. In addition, the PJM transmission owners consulted with PJM, the Organization of PJM States and the PJM Members Committee and submitted the requisite notice of their intention to file the PJM Tariff revisions. While PJM and stakeholders can review and provide input, they do not have the authority to veto or delay the PJM transmission owners' Section 205 filing.

The distribution factor (DFAX) methodology is formulaic and was not designed to be modified on a project-by-project basis; rather, it is a comprehensive formula that determines non-load-ratio~~-~~-share[1] cost allocation~~s~~ based on "beneficiary pays" principles. The DFAX methodology includes, among other things, analysis components such as zonal netting and nesting, the treatment of phase angle regulators, and a threshold for projects included in the RTEP.

In setting boundaries for developing the cost allocation methodology in PJM, the commission made clear that the goal should be to agree upon "a methodology that makes the allocation process routine." In order to accomplish that goal, the commission emphasized that the formula provide for very little discretion by PJM. PJM does not have discretion to create ad hoc exceptions to the FERC approved formula. The methodology is based on a computer model of the PJM transmission system. Using power flow modeling software, PJM calculates the portion of the power that flows on the Required Transmission Enhancement for consumption by load in each transmission zone and withdrawal by each merchant transmission facility. This calculation yields distribution factors, expressed as

[1] Non-load-ratio share refers to an allocation of costs based on factors other than the ratio of a zone's load to total RTO load.

percentages that represent a measure of the use of a transmission facility by the load in respective zones. The distribution factors are calculated for each transmission load zone and merchant transmission facility.

Important characteristics of any methodology are predictability and repeatability, and calculations that are straightforward. The methodology is somewhat complex, as the manual describes; however, the steps are reasonably understandable. And most importantly, the application of solutions-based DFAX has worked well to ensure a reasonable allocation of costs in the overwhelming number of cases. The ex-ante and predictable nature of solutions-based DFAX, along with the fact that it is updated annually to reflect changing uses of the transmission system over time, all work to avoid endless litigation that can ensnare projects needing to move forward to meet PJM reliability needs.

As applied to the Artificial Island project, the allocation meets the Order 1000-required approach. However, given the uniqueness of the stability driver for the transmission project, it is not unreasonable for parties to argue to the regulator for different approaches to the identification of beneficiaries and the cost allocation which results therefrom.

3. Existing Cost Allocation Method: Solution-Based DFAX

The main focus of this paper is to offer for consideration two methodologies for determining the non-load-ratio share component of stability-driven projects like Artificial Island. The existing non-load-ratio-share cost allocation solution-based DFAX method comprises a "use-based" approach that determines the users of a reliability project by transmission zone, relative to all other transmission zones. The methodology uses steady state power flow analysis to determine the usage of a baseline reliability project for each transmission zone and merchant transmission customer with firm transmission withdrawal rights. The existing cost allocation methodology uses a solution-based DFAX approach for identifying the load zones that benefit from a project. The solution-based DFAX calculation quantifies the percent usage of flow on a facility by each load zone. This percentage is then used to formulate a cost allocation to each load zone. Additional information about the existing cost allocation methodology can be found in PJM Manual 14B: PJM Region Transmission Planning Process.

Consistent with Schedule 12 of the PJM Open Access Transmission Tariff (OATT), cost allocation methodologies for transmission projects addressing reliability issues can have both a load-ratio share component and a non-load-ratio share component, depending on the nature of the tariff-defined Required Transmission Enhancement (RTE)[2]. The Artificial Island project is comprised of multiple RTEs. In this paper, in order to provide a representative cost allocation for the entire Artificial Island project, PJM aggregated the different load–ratio-share and non-load-ratio-share allocations for each RTE. PJM used a cost-weighted average of the allocations associated with each of the project's RTEs. This aggregate cost allocation is discussed further in Section 5.

The basic steps of the solution-based DFAX calculations are as follows. The calculation of the DFAX for each transmission zone and merchant transmission facility with firm transmission withdrawal rights is based on its use of the upgrade to deliver PJM generation to serve its load. PJM uses the annual RTEP starting base case to develop all DFAX values for new RTEP enhancements or expansions. A DFAX represents a measure of the use of the upgrade by each megawatt of a zone's load served by a megawatt of PJM generation, as determined by power flow analysis.

[2] RTEs include: (1) Regional Facilities and Necessary Lower Voltage Facilities (as defined in the OATT, Schedule 12[b][i]), which are allocated based on 50 percent load-ratio share and 50 percent non-load-ratio share methodologies; and (2) Other Lower Voltage facilities (as defined in the OATT, Schedule 12[b][ii]) which are allocated 100 percent on a non-load-ratio share basis. The PJM OATT is accessible on-line at http://www.pjm.com/directory/merged-tariffs/oatt.pdf .

To perform a DFAX calculation for cost allocation, both a source and sink for power are defined. The source used for the DFAX calculation is the aggregate of all PJM generation and the sink is each transmission owner's peak zonal load or applicable megawatt values for a merchant transmission with firm transmission withdrawal rights. Using this approach, the simulation observes the change in utilization on a transmission facility as power is transferred from PJM generation to each PJM load zone. This change leads to the calculation of the DFAX value that is an expression of the percentage utilization of a transmission facility by each zone.

The import objective to the Locational Deliverability Areas in which the transmission zone is located will also be considered during DFAX calculation as follows. In modeling the system generation and load, the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA is the external (or internal) Participation Factor and shall equal the ratio of (i) the Capacity Emergency Transfer Objective associated within that LDA (or generation internal to the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the DFAX, PJM distributes these amounts of external/internal generation among all generation in the PJM region external to/internal within the LDA, respectively, in proportion to their capacity.

The following example demonstrates the usage of CETO in the calculation of the internal and external Participation Factors described above. In LDA 1, for example, 66.67 percent of the zonal load in the LDA is served by internal generation and 33.33 percent of the zonal load in the LDA is served by external PJM generation.

Table 1. CETO Application in Participation Factor Calculation for Cost Allocation

AREA	LDA 1	LDA 2	LDA 3	LDA 4
CETO (MW)	3,000	6,000	Less than 0	3,000
Internal Zone Capacity (MW)	6,000	3,000	6,000	0
Internal Participation Factor	66.67%	33.33%	100.00%	0.00%
External Participation Factor	33.33%	66.67%	0.00%	100.00%

A DFAX threshold of 0.01 is applied such that a DFAX with a magnitude less than 0.01 will be set to zero.

For zones embedded in multiple LDAs, the DFAX with the lowest magnitude for a particular upgrade is selected. For example, the JCP&L Zone is embedded within the EMAAC LDA and further embedded within the MAAC LDA. Each DFAX is multiplied by each zonal peak load to determine the zone's use of the upgrade in the direction indicated by the sign of the DFAX.

The megawatt use of the upgrade corresponding to the same directional use of the upgrade is then added and the percentage use by each zone in each direction is calculated. An 8,760-hour (the number of hours in one year) production cost simulation is performed to determine the expected total energy (megawatt-hour) use of the upgrade in each direction for the simulated year. The results are then used to develop a weighting factor (in percent) for each directional use of the upgrade. Finally, the cost allocation percentage is calculated from the solution-based DFAX method by multiplying the percentage use of each zonal load in each direction with the weighting factor having the same directional use of the upgrade.

The analyses are relatively straightforward and can be updated each year to account for changes in flow to the transmission system. The majority of the baseline reliability projects in the RTEP are required to address thermal and/or voltage issues. These thermal and/or voltage issues are often driven by load or transferring energy from generation to load. Projects to resolve these thermal and/or reactive issues often upgrade the overloaded facility or add a parallel facility to reduce the loading on the existing system. Given this, the existing cost allocation method effectively identifies the beneficiaries of the projects that are required to resolve thermal and/or reactive reliability problems.

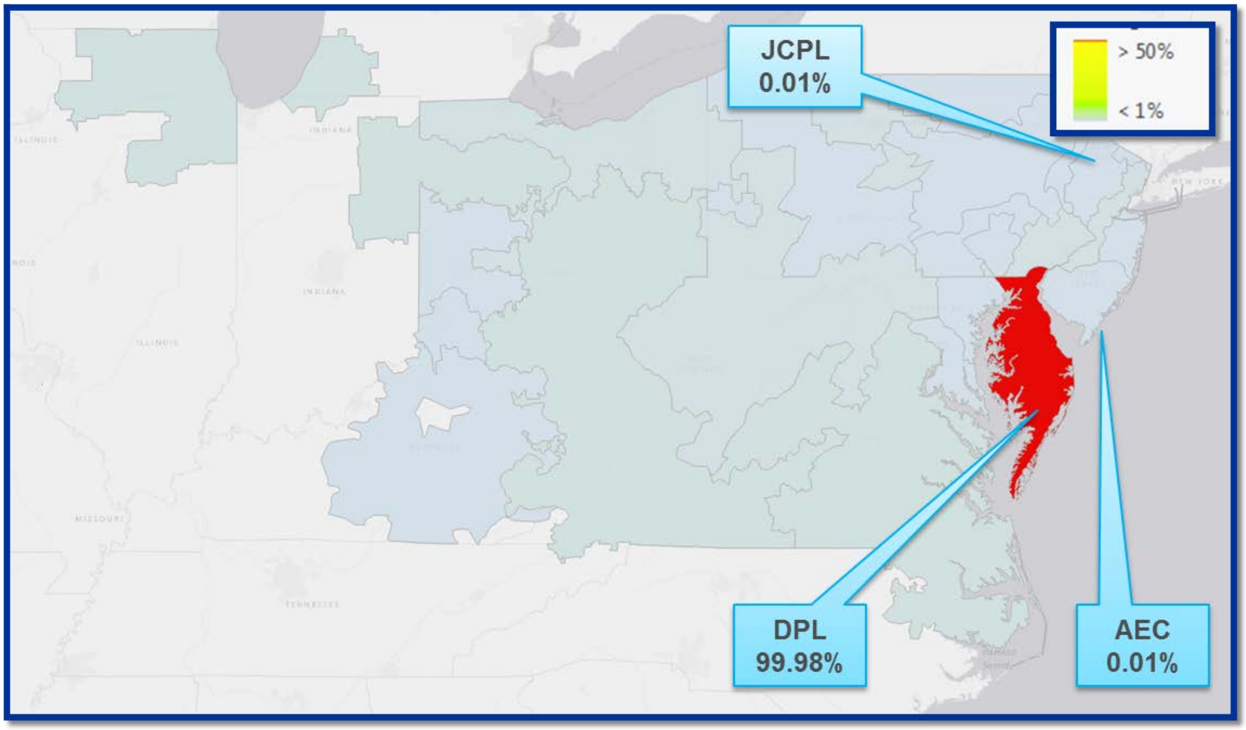
Using the method described above, PJM calculated the following non-load-ratio~~-~~-share cost allocation factors for the Artificial Island Project, shown in Table 2 and Figure 1. (Any totals summing to less than 100 % are due to rounding.)

Table 2. Existing Cost Allocation - Solution Based DFAX

Zone	Existing Method
Atlantic City Electric (AEC)	0.01% ~~0.12%~~
American Electric Power (AEP)	0.00% ~~0.97%~~
Allegheny Power System (APS)	0.00% ~~0.38%~~
American Transmission Systems, Inc. (ATSI)	0.00% ~~0.55%~~
Baltimore Gas & Electric (BGE)	0.00% ~~0.28%~~
Commonwealth Edison (COMED)	0.00% ~~0.91%~~
Dayton Power & Light (DAYTON)	0.00% ~~0.14%~~
Duke Energy Ohio/Kentucky (DEOK)	0.00% ~~0.23%~~
Duquesne Light (DL)	0.00% ~~0.12%~~
Delmarva Power (DPL)	99.98% ~~93.37%~~
Dominion (DVP)	0.00% ~~0.84%~~
East Coast Power Linden (ECP)	0.00% ~~0.01%~~
Eastern Kentucky Power Cooperative (EKPC)	0.00% ~~0.12%~~

Zone	Existing Method
Hudson Transmission Partners (HTP)	0.00% ~~0.01%~~
Jersey Central Power & Light (JCPL)	0.01% ~~0.27%~~
Metropolitan Edison (ME)	0.00% ~~0.13%~~
Neptune Regional Transmission System (NEPTUNE)	0.00% ~~0.03%~~
PECO	0.00% ~~0.36%~~
PENELEC	0.00% ~~0.12%~~
PEPCO	0.00% ~~0.28%~~
POSEIDON	0.00%
PPL	0.00% ~~0.30%~~
PSEG	0.00% ~~0.42%~~
Rockland Electric (RE)	0.00% ~~0.02%~~
TOTAL	100.00%

Figure 1. Existing Cost Allocation Methodology – Solution Based DFAX



4. Alternative Methods of Beneficiary Identification

Stability and Cost Allocation

Power system engineers often talk about the stability of a generator or cluster of generators. A generator (or cluster of generators) is said to be stable if it remains connected to the transmission system following an event or disturbance on the system (e.g. a fault on the system). The stability of a generator is a function of a number of moving parts, including the controls on the generator, the duration of the disturbance, and how well the generator connects to the rest of the transmission system.

PJM is required to ensure the system is stable per North American Electric Reliability Corporation standards and pursuant to the RTEP-developed procedures or criteria to test the stability of generators connected to the transmission system. RTEP upgrades required to resolve stability problems include installation of new controls at the generator such as Power System Stabilizers or incremental upgrades to transmission system equipment, such as faster circuit breakers or protective relay systems.

The Artificial Island project is the first new line that has been added to the RTEP to address a stability problem. As was noted above, using an analytical method that effectively identifies beneficiaries of projects required to resolve thermal or voltage problems may not identify beneficiaries of a stability project.

PJM staff considered a wide range of approaches to identify beneficiaries of stability projects, including various analytical approaches, rule-based approaches and LMP-based approaches. The rule-based approaches – such as allocating the cost of the project to the zone where the unit is located – were dismissed because they are arbitrary and may not be representative of the zones that benefit from the project.

The LMP approaches were dismissed because LMP is not related to stability. LMP impacts on a generator are dependent on aspects such as the generators' heat rate and fuel costs which are unrelated to any of the parameters that impact the stability of the units. Allocating the costs based on LMP or load payment savings related to increased availability of the units would result in a different answer depending on the fuel costs for the unstable unit. In other words, you would get a different allocation for a stability project if the unstable generator was a nuclear plant versus a coal plant or a gas plant. Also, those allocations would change over time based on the cost of one plant versus another and again not because of the improved stability performance. In addition, an allocation method based on LMP and based on increased availability of a resource would require assumptions (that may be arbitrary and change over time) to be made about the increased availability and how that would be reflected in real-time operations.

The analytical approaches included power flow, stability and electrical distance (impedance model) approaches. Some of these were dismissed for various reasons, such as being highly dependent on the system set-up at the time of the analyses (peak load, light load, on-line generation, real and reactive power dispatch and system topology).

Two of the approaches, however, warranted further review and development. A **stability interface DFAX approach** and a **stability deviation approach**. Although the Artificial Island project was used as the test case for developing the alternative approaches, the methodologies would be applicable to any project that is addressing a stability issue for a generator on the system or clusters of generation in an area of the system.

Stability Interface DFAX Method

As noted above, the stability of a generator, or a collection of generators in an area of the system, is dependent on the robustness of the transmission that connects the generator(s) to the rest of the system (i.e. how tightly the generator(s) are coupled to the rest of the system). The Stability Interface DFAX method establishes a closed interface that surrounds the generator(s) with the stability issues. The interface is the collection of lines that connect generators to the rest of the system.

The rationale for the use of an interface is based on the nature of the stability problem requiring a solution. As discussed above, thermal criteria violations are typically a function of a line or transformer exceeding a loading limit under contingency conditions, with the solution being that capability is added to either that facility or generally in parallel with that facility. Stability violations typically are a function of the aggregate of all transmission facilities exiting a generation plant. The solution adds one more transmission element to that aggregate. Examining the problem and the solution related to thermal criteria violations yields generally similar results. By using a circular interface around a generator stability problem, a similar outcome is achieved.

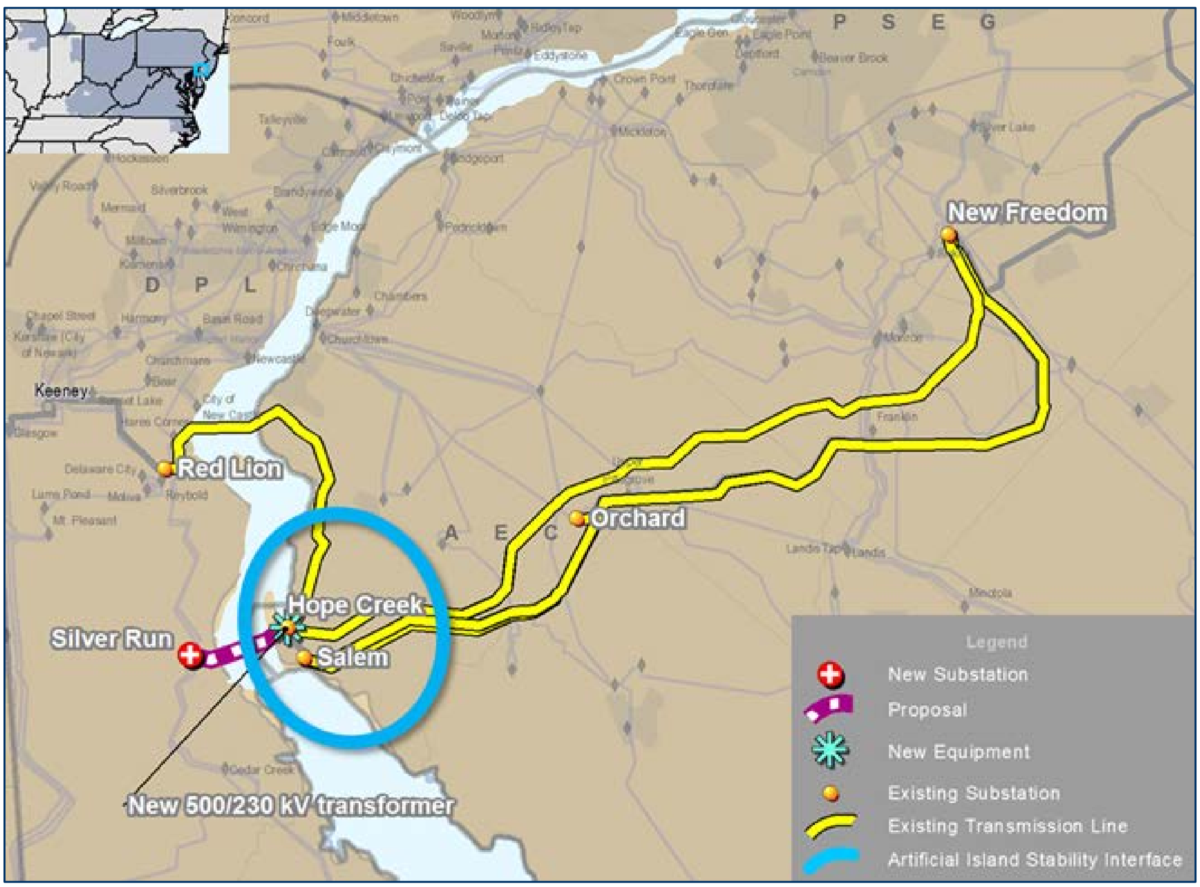
The Stability Interface DFAX method determines the DFAX for each transmission facility that comprises the interface in the same manner as the existing solution-based DFAX cost allocation methodology. DFAX values that are not in the same direction as the predominant hourly usage are ignored. The DFAX for each zone is multiplied by the peak load of the zone. For each zone, the megawatt impacts on each facility making up the interface are added together. These megawatt impacts for each zone form the basis for the allocation.

Developing cost allocations using the Stability Interface DFAX approach of identifying beneficiaries would be relatively easy to implement, given it is consistent with the existing solution based DFAX method. The approach to identifying the stability interface for particular stability projects would need to be captured so that the calculation could be completed consistently in the future.

The interface for Artificial Island would include the following facilities shown in Figure 2~~Figure 2~~:

- Hope Creek 500/230 kV transformer (the low side of which feeds the AI project Hope Creek – Silver Run 230 kV line)
- Hope Creek – New Freedom 500 kV Transmission Line
- Hope Creek – Red Lion 500 kV Transmission Line
- Salem – New Freedom 500 kV Transmission Line
- Salem – Orchard 500 kV Transmission Line

Figure 2. Stability Interface Definition



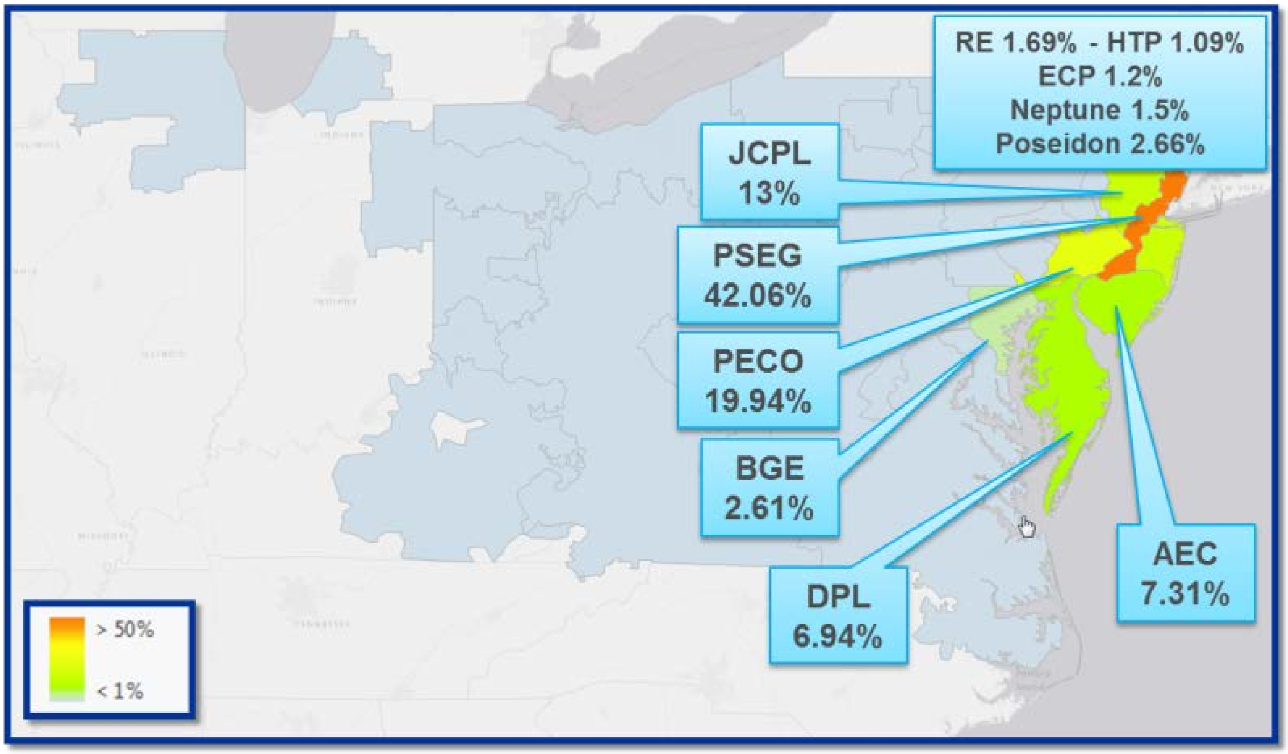
Using the Stability Interface DFAX method described above for calculating the non-load-ratio-share cost allocation for the Artificial Island project yields the example percentages shown in Table 3.

Table 3. Cost Allocation Based on Stability Interface DFAX Method

Zone	Non-Load-Ratio-Share Cost Allocation Component
AEC	7.31%
AEP	0.00%
APS	0.00%
ATSI	0.00%
BGE	2.61%
COMED	0.00%
DAYTON	0.00%
DEOK	0.00%
DL	0.00%
Dominion	0.00%
DPL	6.94%
ECP	1.20%
EKPC	0.00%
HTP	1.09%
JCPL	13.00%
ME	0.00%
NEPTUNE	1.50%
PECO	19.94%
PENELEC	0.00%
PEPCO	0.00%
POSEIDON	2.66%
PPL	0.00%
PSEG	42.06%
RE	1.69%
	100.00%

Geographically, these allocation factors are shown in Figure 3.

Figure 3. Cost Allocation Based on Stability Interface DFAX Method



Stability Deviation Method

The Stability Deviation method identifies beneficiaries of projects by identifying loads that are impacted by critical faults which are evaluated to assess the stability performance of a generator or cluster of generators. The critical faults or disturbances such as the failure of a transmission line or piece of substation equipment, that are typically evaluated to assess the stability of a generator, may involve more severe disturbances that are removed very quickly or less severe disturbances that take longer to be removed, both of which are evaluated under maintenance conditions. Immediately following a disturbance, voltages at all of the substations on the system change with respect to each other and with respect to a common reference. Power system engineers often describe the voltages at a given substation as a magnitude and an associated angle with respect to the common reference. The change in the angle of the voltage is higher for substations that are more impacted by the disturbance or stability event. The Stability Deviation method uses this angle change as a basis to identify those most impacted by the disturbance as the beneficiaries of the stability project.

The first step with this method is to perform a transient stability study for the worst-fault conditions (i.e. the disturbances described above) and monitor the angle deviation at each PJM substation. Mathematically, every location on the electric grid will experience some measureable angular deviation, even if very small. For the purposes of these analyses, PJM selected 25 percent as the threshold. Substations with angle deviations of less than 25 percent of the largest angle deviation would be ignored.

Next, the angle deviation at each substation is multiplied by the load at the substation and summed with all of the other substations in a transmission zone. This establishes a load-weighted angle deviation for each transmission zone. The total load-weighted angle deviations for each transmission zone would then represent the aggregate impact of the disturbance on the customer load in the zone and form the basis for the allocation. Note that there are often multiple worst-fault conditions for a particular generator or generators (e.g. to account for various maintenance outages and critical faults).

PJM identified two line outage/fault condition pairs with the approved RTEP project in place that caused the maximum angle swings at Artificial Island. Then, for the Stability Deviation method example in this paper, PJM included the approved project, determined the zonal allocation factors for both outage/fault pairs and averaged the two sets of zonal allocation factors. Other combinations of outage/fault pairs also could be aggregated (e.g., averaged) for an overall allocation.

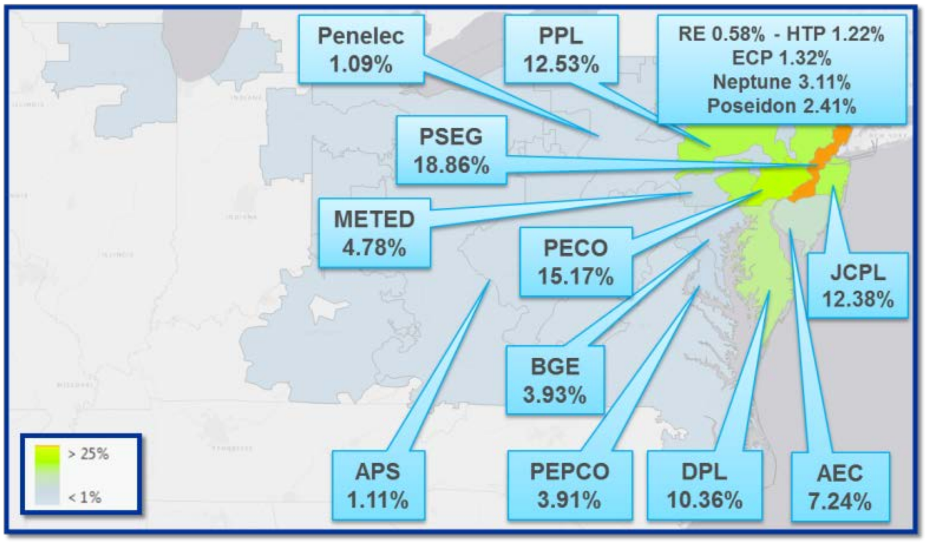
Using the Stability Deviation approach to identifying beneficiaries, the cost allocation for the Artificial Island project is shown in Table 4.

~~Table 3.~~Table 4. Cost Allocation Based on Stability Deviation Method

Zone	Non-Load-Ratio Share Allocation Component (25% Angle Deviation Cutoff)	Zone	Non-Load-Ratio Share Allocation Component (25% Angle Deviation Cutoff)
AEC	7.24%	HTP	1.22%
AEP	0.00%	JCPL	12.38%
APS	1.11%	ME	4.78%
ATSI	0.00%	NEPTUNE	3.11%
BGE	3.93%	PECO	15.17%
COMED	0.00%	PENELEC	1.09%
DAYTON	0.00%	PEPCO	3.91%
DEOK	0.00%	POSEIDON	2.41%
DL	0.00%	PPL	12.53%
Dominion	0.00%	PSEG	18.86%
DPL	10.36%	RE	0.58%
ECP	1.32%		100.00%
EKPC	0.00%		

Geographically, these cost allocation factors are shown in Figure 3.

Figure 3. Cost Allocation Based on Stability Deviation Method



5. Comparison of Methodologies

As indicated in Section 3, PJM calculated the current Artificial Island cost allocation factors consistent with the existing OATT Schedule 12 methodology. In the case of Artificial Island, as shown in Table 5, cost allocation factors for four of the five project elements were lower voltage facilities subject to 100 percent non-load-ratio share cost allocation. The fifth—(b2633.4, the new 500 kV bay at Hope Creek) —was allocated as a regional facility using a 50 percent- load-ratio share and 50 percent non-load-ratio--share cost allocation.

Table 5. Artificial Island Project Element Cost Allocation Basis

Project ID	Description	Cost Allocation Basis	Cost Estimate ($M)
b2633.1	Build a new 230 kV transmission line between Hope Creek and Silver Run	100% Non-Socialized	$129.60
b2633.10	Interconnect new Silver Run 230 kV substation with existing Red Lion - Cartanza and Red Lion - Cedar Creek 230 kV lines	100% Non-Socialized	$2.00
b2633.2	Construct a new Silver Run 230 kV substation	100% Non-Socialized	$16.40
b2633.4	Add a new 500 kV bay at Hope Creek (Expansion of Hope Creek substation)	50% Socialized	$19.00
		50% Non-Socialized	$19.00
b2633.5	Add a new 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation	100% Non-Socialized	$93.90
b2633.91	Implement changes to the tap settings for the two Salem units' step up transformers	100% Non-Socialized	$0.01
b2633.92	Implement changes to the tap settings for the Hope Creek unit's step up transformers	100% Non-Socialized	$0.01

In Table 6, PJM calculated one set of *aggregate* cost allocation factors for the Artificial Island project based on the cost-weighted average of the load-ratio and non-load-ratio shares associated with each project element for each of the three methods described in this paper. More specifically, because 50 percent of b2633.4 is allocated based on load--ratio share, the aggregate cost-weighted allocations in Table 6 are slightly different from the purely non-load-ratio share percentages shown earlier in Tables 2, 3 and 4.

Table 6. Comparison of Cost Allocation Approaches – Aggregate Factors

Zone	Existing Method	Stability Interface DFAX Method	Stability Deviation Method (25% Cutoff)
AEC	0.13%	6.93%	6.86%
AEP	0.97%	0.97%	0.97%
APS	0.38%	0.38%	1.41%
ATSI	0.55%	0.55%	0.55%
BGE	0.28%	2.72%	3.95%
COMED	0.91%	0.91%	0.91%
DAYTON	0.14%	0.14%	0.14%
DEOK	0.23%	0.23%	0.23%
DL	0.12%	0.12%	0.12%
Dominion	0.84%	0.84%	0.84%
DPL	93.37%	6.65%	9.84%
ECP	0.01%	1.13%	1.24%
EKPC	0.12%	0.12%	0.12%

Zone	Existing Method	Stability Interface DFAX Method	Stability Deviation Method (25% Cutoff)
HTP	0.01%	1.03%	1.15%
JCPL	0.27%	12.37%	11.80%
ME	0.13%	0.13%	4.58%
NEPTUNE	0.03%	1.43%	2.93%
PECO	0.36%	18.95%	14.50%
PENELEC	0.13%	0.12%	1.14%
PEPCO	0.28%	0.28%	3.93%
POSEIDON	0.00%	2.48%	2.25%
PPL	0.30%	0.30%	11.98%
PSEG	0.42%	39.63%	18.00%
RE	0.02%	1.59%	0.56%
Total	100.00%	100.00%	100.00%

Conclusion

The results and the material presented above are not intended to represent an exhaustive analysis of all of the possible approaches to identifying beneficiaries related to the Artificial Island project or the resolution of grid stability issues in general.

The Stability Interface DFAX method relies on the same analytics as the existing allocation methodology. Based on that consistency, it would be easy to implement and should be familiar and readily understood. In addition, since the method relies on the same analytics, the cost allocations could be updated on an annual basis (as are the allocations for thermal criteria-based projects). Regarding possible variants of the Stability Interface DFAX methodology, it may be appropriate to consider weighting the use of individual facilities comprising the interface other than equally, as was done here. There also may be circumstances where the interface should be comprised of facilities other than the immediate exits from a particular generating station as would be the case if the project were addressing stability of a cluster of generators within an area of the system. For the methodology to be generally applicable to future stability criteria issues, such questions should be discussed further.

The Stability Deviation method is more directly linked to stability-based analytics and may, therefore provide a more representative identification of beneficiaries. However, while more analytically related to the nature of the problem, the method may be more difficult to understand and replicate. The method also relies on the identification of a threshold below which no costs are allocated. Regarding possible variants to the Stability Deviation method, it may be appropriate to evaluate the response to a number of critical fault conditions and weight the results in some fashion. Additionally, analysis of alternative percentage thresholds (used in the method) may provide value.

Revision History

Revision 0 - June 9, 2017

Revision 1 - June 29, 2017

- p. 3 – Clarified aggregate cost allocation in light of load-ratio-share and non-load-ratio-share components
- p. 5 – Revised Table 2 to show Solution Based DFAX Non-Load-Ratio-Share allocation factors, not aggregate cost allocation factors
- p. 6 – Revised Figure 1 map with one showing Solution Based DFAX Non-Load-Ratio-Share allocation factors, not aggregate cost allocation factors
- p. 8 – Added a list of transmission facilities that could comprise an AI stability interface
- p. 9 – Added Figure 3 to show the geographic location of transmission facilities that could comprise an AI stability interface
- p. 9 – Revised Stability Interface Table 3 to show non-load-ratio-share cost allocation factors
- p. 11 – Revised Stability Deviation Table 4 to show non-load-ratio-share cost allocation factors
- p. 12 – Added Table 5 to show cost allocation basis for each AI project element
- p. 12 – Added text to discuss comparison of AI project aggregate cost allocation factors
- p. 12 – Revised Table 6 show aggregate cost allocation factors, not non-load-ratio-share cost allocation factors