BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the matter of : ER15-2562-000

PJM INTERCONNECTION, L.L.C. : ER15-2563-000

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CONSOLIDATED EDISON COMPANY : EL15-18-001

OF NEW YORK, INC. :

-vs- :

PJM INTERCONNECTION, L.L.C :

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DELAWARE PUBLIC SERVICE : EL15-95-000

COMMISSION and MARYLAND PUBLIC :

SERVICE COMMISSION :

-vs- :

PJM INTERCONNECTION, L.L.C. :

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LINDEN VFT, L.L.C. : EL15-67-000

-vs- :

PJM INTERCONNECTION L.L.C. :

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PJM INTERCONNECTION, L.L.C. : ER14-972-003

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PJM INTERCONNECTION, L.L.C. : ER14-1485-005

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Room 3M

Federal Energy Regulatory Commission

888 First Street, Northeast

Washington, D.C. 20426

Tuesday, January 12, 2016

The technical conference in the above-entitled matter was convened at 10:00 a.m., pursuant to Commission notice.

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P R O C E E D I N G S

P R O C E E D I N G S

(10:00 a.m.)

MR. LeCOMTE: Welcome to PJM's solution-based distribution factor cost allocation method conference. Thank you all for attending.

If I could ask everybody who's dialed in, please place your phone on mute so not to interrupt the conference, thanks.

And directed in the November 24th, 2015, order and noted in subsequent notices, staff will explore both whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the plan and transmission facility, and whether an alternative just and reasonable ex-ante cost allocation method could be established for any such category of projects. This is a staff-led technical conference and any statements or comments made at this technical conference represent the views of Commission staff and not the Commission.

Please note that this technical conference is being transcribed in order to provide an accurate record. For the benefit of those monitoring the conference by telephone or in person, please always state your name and if you've not already done so, who you will be representing and speaking. Please place your table tag at its edge if you wish to speak, and wait for the microphone. Because they may interfere with room communication equipment, please silence your phones.

I would like to begin with staff introductions, noting that different staff may be present during different times of the day, followed by panelists introductions.

MR. FEUERSTEIN: I'm Jason Feuerstein with the Office of Electric Reliability.

MS. ADAMS: Keatley Adams, Office of Energy Markets Regulations.

MS. ATHWAL: Moon Athwal, Office of General Counsel.

MR. GROSS: Ed Gross, Office of Electric Reliability.

MR. ROLASHEVICH: Good morning and welcome, Pete Rolashevict, economist.

MR. LeCOMTE: Ron LeComte, OGC.

MS. MARTIN: Valerie Martin, Office of Regulations.

MR. FOSTER: Ben Foster from the Policy

Office.

MS. TEETER: Valerie Teeter from Office of Energy Policy and Innovations.

MR. MATYAS: Doug Matyas, office of OEMR East.

MR. JONES: Kevin Jones, OEMR East.

MR. GOLDENBERG: OGC.

MR. LeCOMTE: And on that side the panelists could introduce themselves.

MR. FARBER: Good morning. John Farber for commission staff.

MR. WEISHAAR: Bob Weishaar on behalf of the Delaware Public Service Commission, Maryland Public Service Commission, the Delaware Division of Public Advocate, and the Maryland Office of People's Counsel.

MR. WOOD: Jeff Wood with Hudson and Neptune Transmission.

MS. FISHER: Amy Fisher, Linden VFT.

MR. SASSON: Mayer Sasson, Con Edison.

MR. HERLING: Steve Herling with PJM.

MR. RINGHAUSEN: Mark Ringhausen with Electric Cooperative.

MR. KHADIR: Esam Khadir with the PSEG.

MR. RICHARDSON: Frank Richardson with the PJM Transmission Owners.

MR. LAIOS: Takis Laios with the PJM Transmission Owners.

MR. LeCOMTE: Thank you so much. If I could again remind those who have dialed in to please place your phones on mute. We will allow up to ten minutes for opening comments. I will again note that the Commission directed staff to explore whether there is a definable category of reliability projects within PJM for which a solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on a planned transmission facility, and whether an alternative just and reasonable ex-ante cost allocation method could be established for any such category of projects. We recognize that there are many issues that could be discussed at this technical conference; please keep your comments on point.

You are to efficiently address the Commission's directives. I will cut off questions that go beyond the scope of the Commission's directs. A schedule for post-technical conference comments will be announced in the afternoon session. I just wanted to make one statement for those on call: To the extent you have questions, I understand in the notice that the PJM defects CONF designated list had not been accessible from outside. That should be corrected. If you get a bounceback on that, please send an e-mail to ron.lecomte@FERC.gov. Thanks so much.

I'd like to start with PJM interconnection presentation. Thanks.

MR. HERLING: I was just going to make a few comments. We had provided a table of the number of projects that fell into various distinct categories based on the nature of the problem they were intended to resolve. Just to be clear, the numbers, we rolled up sub-elements of projects. If you go back to the individual cost allocation sheets, you will see far more elements that are allocated than the number of projects in that table. And that's because for a given problem the solution may have two or 10 or 15 sub-elements; we're trying to represent the number of projects resolving problems, so. As you can see, the vast majority of projects are related to either thermal criteria violations or voltage problems. It's our belief that the solution-based defects is entirely appropriate to deal with the solutions to those types of problems. It works well initially, it works well over time. That really was the benefit of moving to the solution-based defects a few years back.

We also identified a couple of lesser

categories, operational performance was one of the smaller categories that had a larger number of projects. Those are often related to operational flow issues or operational voltage issues. And, again, we believe that the solution-based DFAX is an appropriate approach to allocate the solutions to those problems. The remaining categories were aging infrastructure, which are a fairly recent one. There, for the most part, the flows are readily represented by the solution-based DFAX and then we really don't have any issue there. And then you have the stability issues which there really has only ever been one that was not captured in a generator interconnection study. And short circuit.

Now, there have been a great many short circuit problems that have been resolved in the RTEP, but in all cases but one they have been resolved by upgrades to the circuit breakers at a particular substation, or they have been part of the solution to a thermal problem where you build a line and the line over duties the circuit breaker and as a result the replacement of the circuit breaker is associated with the line project. So there's only ever been one short circuit problem that had to be resolved by something other than the replacement of the circuit breaker. In the short circuit issue and the stability issue, again, the benefit of solution-based DFAX over time does represent the flows that are made on the facility that is solving the problem, okay. The initial nature of the problem may not necessarily be related or entirely related on those flows, but over time the evolving use of the facility is well-represented by the solution-based DFAX. One of the challenges -- and as we talk through this today and in the future with identifying the cause of a problem -- if you look at the short circuit issue, for example, there is no one single cause that you can point to to that particular short circuit problem. It's something that kind of evolved over time as a great number of solutions were put in place that had very small impacts on the fault duties at the substations in question. And in a given year we may have 100 projects that are introduced into the RTEP. Each one has a very small impact. We may add generators; there may be generators added in New York that have a small impact on the fault duties. So as we move forward we'll find that it's going to be very difficult to point to a single causal element that you could say on day one is the reason why we had to change out -- in this case not change out a circuit breaker but build a line to redirect fault currents. So over time the solution-based DFAX works pretty well.

We can talk about whether on day one the flows on the solution may not be entirely representative of the reason why we had to build the line in the first place. And I think that's really what your question is getting to, the stability is kind of the same situation. On day one the flows on the line is solving the problem are partially representative of the problem but not entirely representative.

And at this point I think I'll defer any remaining time and take questions later on.

MR. LeCOMTE: Thanks, Steve.

Somebody who's called in has not got their speaker on mute and it's very disturbing. If you would all check and make sure that your phones are on mute, that would be very much appreciated. Thank you.

PJM Transmission Owners.

MR. RICHARDSON: Good morning. Takis and I are representing 16 companies that are PJM Transmission Owners in PJM. The 16 Transmission Owners have a collective responsibility for the design of their current PJM RTEP cost allocation methodology. We have considered the comments submitted by the parties in the technical conference and we continue to support the current cost allocation methodology as the best available. We hope our comments this morning and the discussions today will provide more informed context for the Commission to make decisions within. We view the comments submitted as representative of kind of a microcosm of what happens when cost allocation is not performed using an objective, repeatable measurement of benefits based on accepted engineering principles. When cost allocation is left to concerns, perceptions, and opinions, we have what we have before us, a comment today. Where no entity is put forth, as the Commission requested an alternative, neutral, and objective ex-ante cost allocation method or rational delineation of the subset of reliability projects to apply it to. Instead we have commenters on topics of both sides, Delaware and New Jersey in the case of the artificial island project cost allocation. We have parties who want to revert to causation principals in allocating for claiming, "I didn't cause the problem. I don't benefit from the solution" in order to put costs on others. We have parties who want to discard the methodologies we have for actually measuring the benefits of reliability projects and exchange it with the measure of economic benefits to put the cost on others. We have parties who want to modify solution-based DFAX, calculations, to put costs on others. We have parties proposing special cost allocation rules to be applied just for merchant transmission facilities to put costs on others. We have parties proposing a definition of benefits unique to merchant transmission facilities to put costs on others. And lastly we have parties who arbitrarily declare that the solution to this problem is to put all charges to the local zone, charge all zones, charge generators, and do that, and in addition we'll take a rule allocation along with that as well. And all of these propositions are focused on singular projects of concern to the commenters, and all of the propositions are designed to their benefit. This is representative of what happens when projects are looked at in isolation or we revert to causation as the basis for cost allocation.

What we do not have in the comments is an alternative methodology ex-ante, it's repeatable, it's an objective measure of benefits that works across geography, across time, and across all types of reliability projects. We do have that in a solution-based DFAX methodology; it's the best method available. It's based on industry-accepted engineering principals, not perception, appearance, or the party's unsupported opinion of "this is who I think should pay for this." The Transmission Owners offer that specific cost allocations should not be evaluated in isolation of all the other integrated components of the PJM schedule cost allocation methodology in considerations outside of just the DFAX methodology that result in some parties being exempt from certain costs and other parties paying certain costs. The cost allocation process and methodology has to be taken as a whole, looked at as a whole, and should not be attacked piece by piece in isolation of each other, project by project, and singling out the DFAX component of the entire cost allocation methodology. We believe attempts to categorize reliability projects differently will be fraught with problems and will lead to more litigation.

For a large percentage of reliability projects there are multiple violations and reasons causing the need for the project, as well as future violations that will be mitigated. Time to agree upon and split out the causes of allocations will be subjective, circular in reasoning, riddled with conjecture, and will be argued project by project because each of the projects are unique. Because of this, the Transmission Owners changed the game with our last cost allocation of filing and focused on objectively measuring the use of the facilities to measure for cost allocation, and to put that controversy to an end by going to measuring the use. As the New Jersey parties wisely point out, ultimately every project is for waste, regardless of the cost or the need for the project. The Transmission Owners believe that cost allocation can be perceived as unfair but project by project alterations to the PJM cost allocation methodology is not proper. Change to the cost allocation methodolgy should be evaluated over long periods of time with a mounting body of evidence over a larger amount of projects and as an integrated whole, and not in the context of a single project cost allocation where there will be winners, there will be losers, and there will be losers who will litigate, and that won't jeopardize the progress that we have complexed so far with the cost allocation methodologies and PJM.

Solution-based DFAX measures use of the transmission facilities. Some results may look strange, at times benefitting the entity and at times not benefitting entities. It is not arbitrary, it is defensible and it's the best method that we have. There's no perfect measure of benefits, nor an alternative, and we should be cautious about making any changes. We look forward to more discussion this afternoon. Thank you.

MR. LeCOMTE: Thanks.

Presentation on ConEd, please.

MR. SASSON: Thank you to the Commission for bringing this conference to explore two over-arching questions. First, is there a category of reliability projects where the DFAX analysis does not work? Our answer is yes. The DFAX analysis is simply the wrong cost allocation method for transmission projects that are intended to resolve non-flow-based violation and provide non-flow-based benefits. I'll refer to such projects as non-overload projects. The DFAX analysis relies on energy flows, but the non-overload projects such as the Bergen, Linden, or the VFT to garner artificial island projects, there is no rational relationship between flows and intended beneficiaries, which I will explain.

Any flow-based benefits that may result from these and other non-overload projects are incidental to their intended benefit and their stated purpose. Some parties have argued that it is difficult for PJM to identify which category a project belongs in; that is incorrect. PJM already makes distinctions today. For example, when PJM filed a cost allocation for the BLC project with the Commission it identified their relief problem as over-dutied breakers, and the fail criteria short circuit. And the final cost allocation for this failed to identify the problem as damage due it Sandy, and the failed criteria as a piece of criteria. PJM also brought in a matrix in advance of this technical conference, as Steve just mentioned, the device projects according to their purpose. Clearly, this is something PJM does and can do.

On the second question: Is there a just and reasonable ex-ante cost allocation method for non-overload projects? Again, our answer is yes. The Federal Power Act requires cost allocations to be just and reasonable. Among other things, this required the Commission to make an affirmative finding that costs are at least roughly commensurate with benefits for non-overload projects. This means adopting a cost allocation method that first and foremost identifies which transmission zones are the projects intended beneficiaries. And since intended beneficiaries cannot be identified by flows, they must be identified by reference to the intended purpose of the project.

A practical matter: This means allocating the costs of non-overload projects to the transmission zone or zones that benefit by receiving relief from the non-overload issue. Some parties have claimed that this would be a violations based approach; we've gotten that complaint. But that conversation is incorrect and serves only to obscure matters by hardening the facts to disputes. Let me be clear: Con Edison is not advocating a violation-based DFAX analysis period. Our position is that for non-overload projects no defect, violations, solutions, no DFAX analysis can apply because there is no rational or technical relationship in the flows and intended beneficiaries. The only justifiable way to identify prospective beneficiaries for non-overload projects is to identify who it's intended to benefit, given the project's purpose.

I will now discuss a little bit more depth -- and I do note that it is summarized in a couple slides that we have that are out there, you can take a look at. With respect to the first question, DFAX analysis is the wrong cost allocation method for non-overload projects because it relies on distribution factors which lead to flow-based measures. Distribution factors are the basis to quantify the amount of flow that each individual load contributes to the total flow over a specific line. Distribution factors are multiplied then by load to get flow, which are then used for cost allocation. For example, a load has a distributing factor of two percent relative to a given transmission line means that two percent of that load flows to that line. But for non-overload projects, there is no rational relationship between the flows and the intended benefits. This makes the use of distribution factors as part of a DFAX analysis a portion of it.

For example, the purpose of the BLC project is to address short circuit violations. Short circuit has nothing to do with energy flows. Energy flows are the result of customer demand. Short circuits are part of the system that are disturbances of the result of generator current of an overwhelmed circuit breaker. Because short circuits have nothing to do with energy flows, the intended benefits of fixing a short circuit cannot be measured by flow. The same is true for the Sewaren Project. The Sewaren Project is intended to rebuild the system damaged by Storm Sandy. If it can be recovered, it's not a benefit that can be measured.

Finally, the artificial island project is intended to enhance stability, not enhance growth. For these and future non-overload projects the DFAX analysis is the wrong tool to use and using it will necessarily result in cost allocations that are unjust, unreasonable, unduly discriminatory, and not wrought with the message of benefits. With respect to the second question, it is important to make one threshold point: Some parties in these proceedings have argued that Con Edison and others had no right to challenge their cost allocations for any individual project so long as the DFAX analysis worked for most projects. We categorically reject that position. It gives each party a right to adjust the reasonable cost allocation for each and every project, as well as the unqualified right to challenge any cost allocation that it believes fails this step. To ensure that costs are just and reasonable and at least roughly commensurate with benefits, the cost allocation method for none of our projects must identify intended beneficiaries. If intended beneficiaries cannot be identified by flow, they must be identified by reference to the intended purpose of the project. For short circuit projects like the BLC projects, intended beneficiary is the transmission zone where the short circuit exists. Why? This is because excessive current, if not removed, will result in the physical damage and the physical failure of equipment in that degree. This conclusion is supported by two additional points: First, short circuits are usually resolved through the interconnection process and paid for by the interconnecting party. Second, as PJM has stated, the typical solution for a short circuit problem is to repair roughly the break, not to build a transmission line. This underscores the rationale to measure benefits of short circuits.

The VLC project became necessary in this case only because higher capability breakers are unavailable. This is the first time that this came out. But make no mistake about it, the BLC projects intended to fix short circuits in each serviced territory and not flow. And as PJM recently informed its stakeholders -- this is interesting -- the entire BLC project remains necessary with or without the flow. Clearly, this is for the intended beneficiary. Similarly, storm recovery and other projects like the Sewaren Project to be allocated to the transmission zone where the infrastructure exists, because clearly that is where the intended beneficiaries are. Indeed, before a state regulator, the Sewaren Project as its number one priority for post-Sandy substation repairs.

Finally, because the systems that are connected across transmission zone boundaries, disturbances that create the stability issue can affect generators in different transmission zones. Consequently, the cost of stability projects such as the artificial island project should be allocated in a breaker-shared basis to the transmission zones where the stability issues are served. So I note that Con

Edison's proposal exactly allocates cost intended beneficiaries and is easy to implement. Thank you.

MR. LeCOMTE: Thank you, Mayer.

Amy?

MS. FISHER: Amy Fisher with Linden VFT. In light of what we believe are glaring shortcomings in the PJM open access transmission power Schedule 12 cost allocation process, Linden VFT is pleased with the consent Commission understands the 2013 RT cost allocations, which we have protested, may not be just and reasonable. We're in general agreement with Con Edison that it benefits the project which do not address a need for increased power flow, should not be measured by proxies based on relative power flow. Several of the 2013 RTEP projects addressed local short circuits violations in the central portion of the utility load zone by rerouting the current among additional substations. Whether those substations also interconnect at or near Linden VFT will determine whether Linden VFT is allocated costs to resolve this short circuit problem. Had the local utility decided to spread the current within its own load zone, Linden VFT would be allocated fewer or no costs.

Regardless of which individual substations are allocated, the short circuit problem will be resolved. However, the cost allocation will dramatically stay. If the utilities plan, counsel working at the local VFT local connection point a significant cost allocation could be shifted for Linden VFT even though Linden VFT received no benefits to offset those costs.

Another 2013 RTEP project is repaired existing substation following damages caused by hurricane Sandy, the Sewaren Project which Mayer referred to. It, too, was planned to permit the local load serving entity to fulfill its ratepayer obligations, and the criteria project was not needed to address reliability, market efficiency, or public policy requirements. Our addition to Schedule 12 as has been proposed would be helpful if it clarified the different types of transmission expansion projects, may require different proxies to determine project benefits. By the way Linden VFT reads Schedule 12 to require differential readiness, but PJM disagrees. However, if so modified, Schedule 12 would not be a valid ex-ante project to cost allocations, at least to the extent applied to us. Ex-ante cost allocations formulas can simplify cost allocation determination as to expense, but they only justify to the extent that they produce results which are fair. Under relative law that means cost allocations which are roughly commensurate with benefits received. Applications and ex-ante formula in a way that violates that standard means the ex-ante formula is wrong, even if the formula may often work as intended. A potentially responsible payers' concern is an indication that the ex-ante formula may not be producing results that are roughly commensurate with benefits. It should be taken seriously, not trivialized.

The Northern New Jersey project clearly provides significant local benefits, far more significant than the undocumented powerful advantages which are presumed to across on the Linden VFT. The cost allocation mistake is not outweighed by the value of an ex-ante formula because knowing beforehand that the formula will produce legally invalid results will only lead to bigger problems following the application of the formula. However, the load serving entities remain unwilling to concede that the grand bargain which they collectively agreed to in 2012 does not work, at least in some cases.

The Commission was told at that time that the resulting ex-ante formula, which is referred to as you know as the solution-based DFAX, employs use of a transmission upgrade as a proxy for the benefits of that upgrade, and that this rule would always, always produce cost allocations which were roughly commensurate with benefits. In fact, under Schedule 12 in order to produce a roughly commensurate result the solution-based DFAX result only becomes cost allocations after application of savings rules. The one percent de minimis netting rule in the related gross of provision, which we've talked about. These effectively allow the LSE's to limit their contributions to projects outside their own load zone, thus the ex-ante formula is not due to equal benefits as you have heard. But use of the proxy for benefit except when that would not make sense for LSE. Such a formulation might pass if it were not for the fact that the savings rule significantly discriminate against Linden VFT and similar parties, and therefore provides none of the consensus-driven planning and coordination value which the Commission associates with ex-ante rules. What this ex-ante formula is able to do is permit the load-serving utilities to calculate in advance the ability they will have to offload the cost of their upgrades on to other parties and to design those upgrades to take advantage of the arrangement.

To be clear, the most well intentioned LSE has incentives in the application of Schedule 12. It an LSE expects to flag transmission concerns, plan the solution, and add the resulting project to its rate base. It can also eliminate ratepayer concerns if the projects are assigned to other system users. The claim by the PJM LSE's that the projects Schedule 12 cost allocation methodology worked well is over stated. As we have indicated, it is not 95 percent of the allocations that worked just fine, but rather when you calculate only those projects that were used, that solution-based DFAX was used to cost allocate, you end up with 74 projects, seven of which were completely allocated to the local load zone and therefore not contentious, and 60 of those 74, 81 percent, are the subject of protest.

In addition, litigation sought by the western LSE's in 2005 resulted in a major revision to the previous ex-ante methodology which presumably everyone thought was fine at the time, as recently as 2012 and in that case has still not been fully resolved.

PJM's prevailing view is that there are no bad projects, only bad cost allocations. And it takes no responsibility for cost allocations, it merely applies the formula given to it by the LSE's. However, divorcing project selections from cost allocation is bad policy because separating the question of what to build from the question of who benefits from upgrades also eliminates important checks and balances in assessing the timing of the specific projects. Under the PJM TO, cost allocation information with respect to a proposed project does not relieve until the project has been sent to the PJM board for approval. Failure to consider cost allocation in project allocation means that more efficient in cost effective have no objective meaning. It is nonsensical to state that a larger regional project is less costly than a series of smaller local projects without considering the question of less costly for whom. An RTEP example of how this working practice is the Bergen-Linden corridor project which includes the new substation for Newark Airport, important locally but without benefit to Linden VFT. Had it been clear at the time of project design and selection that Linden VFT and not the New Jersey ratepayers would be bearing that project cost, questions about benefits received would have been obvious. Instead under the current OATT there is literally no one who considers the cost benefits to Linden VFT of that decision.

We can see from the comments of the artificial island cost allocation component that they have made the suggestion that all projects be evaluated under economic criteria to try to put some limit on the planning process. Linden VFT contends that the PJM RTEP rule require consideration of the issues already. The regional transmission expansion planning protocol is required to avoid the imposition of unreasonable costs on any transmission owner or any user of transmission facilities. Section of the OATT requires that any cost assigned to an MTF be reasonable. Instead the cost allocation results for the New Jersey project is that 890 million out of the total of 1.1 billion are the responsibility of parties other than the LSE in undeniably not just and reasonable. The likely result of this cost allocation will be that the parties who receive the allocations will be forced to relinquish their rights. Since the New Jersey projects upgrades are according to PJM still necessarily, as Mayer pointed out, they will be paid for by the load zone in which they are located after all. But the resources 1,600 plus megawatts will be lost. This is the local minority disparagingly referred to by the New Jersey Board of Public Utility.

We remind the Commission that MTF are different and MTF is not an electric load, it's a transmission line. In Linden VFT's case it's a type of transformer. In PJM an LEC's determination to add a transformer will be studied to determine its effect on the system and costs to address resulting changes will be included as but-for costs. MTF also pay their but for costs through a generator-like interconnection process. No one suggests that a utility transformer, once incorporated into the grid, should attract ongoing upgrade investments. Also, MTF is not a traditional load zone, which is user and energy producers. It is simply a device which power delivered over PJM lines of the somewhere else, and in the case of Linden VFT loads them back somewhere else. The price of power region determines where that power goes. Although PJM must be aware of the plan of system and FTS does not use power in the way that rate payer load does. There appears to be a belief among some parties to this dockets that MTF's are not paying their fair share of system costs when there is a withdrawal of power from Northern New Jersey, and this view is wrong. With respect to energy transfers, PJM and NYISO conduct their own procedures under coordinated transaction scheduling. A generator can choose which market to participate in.

Linden VFT energy flows are no different. If a Linden VFT customer determines to participate in the Newark capacity market, it delists in PJM and doesn't receive capacity payments from PJM. Market forces determine where generation is best allocated and drive price convergence between regions exactly as desired under this Commission's interregional planning principle. The fact that an MTF may facilitate these options for generation does not just guide the imposition for cost allocations, which benefit does. So what is to be done? First and foremost, all parties need to recall that cost allocations must always be commensurate with the benefit a party receives and no parties are entitled to be free riders. Projects which have their underlying purpose of allowing a service in the zone given the age of existing infrastructure, damage to existing equipment, short circuit currents, and similar upgrades, are more fairly allocated to the load zone which would allow those projects to be assessed by state regulators to determine cost containment.

The LSE's would like to maintain the existing 12 formulation, at least for the bulk of power flow process where it results to sponsoring loads, sparing the bulk of project cost. Subjects to review and analysis, Linden VFT main have no objection to those as long as the LSE's are willing to revise the formulations so as to provide savings benefits to MTF so that incidental benefits are not the basis of cost allocation for them. This means an equivalent de minimis figure which would serve to reduce the facilities for which Linden VFT is responsible and netting concepts that give it back to MTF peak-load operation, and reasonable determination of the likely sources of the MTF generation, each of which is comparable to existing rules for LSE's. It also means rethinking the growth provisions of Schedule 12 which exclusively reallocate costs from beneficiaries to non-beneficiaries. Acknowledgement in Schedule 12 to be made at MTF are not traditional load zones but are transmission facilities.

Linden VFT's facilities needed repair last year. Linden VFT performed that work without any consideration of contribution from other load zones, even though it maintained 330 megawatts of capacity transmission injection rights which provide a benefit to those PSEG load zones in the form of additional generation under peak conditions. That's the deal. MTF caused zero revenue recovery parties under the consolidated transmission owners agreement for a reason. But conversely no MTF can be responsible for maintaining the unit portion of the transmission facilities of another party. We cannot see the benefit of these upgrades to our operations and our customers confirmed them in our open season solicitation. This is not increased as a result of impending upgrades and our customers will not even provide bids to use our service if RTEP costs are imposed upon them.

Finally and very importantly, PJM should accept responsibility for administering its own power in accordance with its terms which requires an assessment of cost allocation in the project selection process, timely and complete information provided to affective parties through the RTEP process, and a reasonableness review of Schedule 12 results. If PJM does not perform these functions, parties will be forced to contest Schedule 12 results of the Commission and in the court to assure that they meet long established standards of fairness.

Thank you for allowing me to participate and I look forward to questions.

MR. LeCOMTE: Thank you, Amy.

Bob or John?

MR. WEISHAAR: Thank you and good morning. I'm Bob Weishaar, speaking on behalf of the Delaware Public Service Commission, the Maryland Public Service Commission, Delaware Division of Public Advocate, and the Maryland Office of People's Counsel.

Artificial island is an area on the eastside of the Delaware river that is seldom more than 3,000 megawatts of nuclear capacity. We're close to three decades that nuclear capacity has been operating subject to what's known as that artificial island's operating guide. In spring 2013 PJM determined that an RTEP project should be developed to address these stability issues that are currently being addressed via the operating guide. And after an extensive RTEP process involving many competing proposals over a rather lengthy period of time, PJM ultimately settled on a combination of projects to be developed by LS power, PSEG, and PHI. The total estimated cost of the project is more than a quarter billion dollars. Of this total cost approximately 246 million or 89 percent of the total is proposed to be allocated just to the Del Marva zone. Of the SBD facts portion of the project, 99 percent of that total is proposed to be allocated just to the Del Marva zone. At the Delaware Public Service Commission's request, PJM conducted an economic benefits analysis, essentially the same market efficiency analysis that PJM conducts under Schedule 12, section B5. That analysis revealed that only 10 percent of a total benefits of the project would go to the Del Marva zone. This mismatch between an allocation of 90 percent of total project costs and 10 percent of project benefits are why John and I are here today. The state agency has exhausted all options in the PJM stakeholder process. They participated extensively in the TO act: They wrote letters to the PJM Board; they presented proposals to the TOAAC; they had extensive discussions with PJM and individual Transmission Owners. All of which led up to what we have here today in terms of the record.

In looking at the record, I think it's helpful to distinguish between the issues that are uncontested and the issues that are still contested. Uncontested is the fact that artificial island is a stability-based project. It is not being developed to address thermal or voltage violation. Uncontested is the fact that approximately 90 percent of the total costs of the artificial island project are proposed to be allocated to the Del Marva zone under the existing cost allocation proposal. Uncontested is PJM's economic analysis based on LMP-based energy savings showing that all zones in PJM, with the exception of the Commonwealth Edison zone, will realize at least some economic benefit from the artificial island project. The only contested issue is what we do about the gross mismatch between cost and benefits.

And of all the parties to the proceeding, only the PJM TO's and just recently the New Jersey's state agencies suggest that we just ignore the gross mismatch between costs and benefits, that somehow artificial island is a sufficiently flow-based project to fit within the current SBD facts paradigm or that somehow SBD facts will produce rough justice. Neither of the parties states exactly how that will occur in the end.

PJM itself recognizes that it performs the proposed cost allocation for artificial island based on SBD facts and consistent with Schedule 12 of the PJM tariff, but that equity issues exist. As the PJM Board noted in its July 12, 2015, letter, it recognizes the valid concerns recognized by Maryland and Delaware and others. And in its words, PJM must follow its tariff. And with regard to the cost allocation provision applicable to this project, PJM also must respect legal precedent in the Atlantic City case, allocating specific rate filing responsibilities between PJM and its Transmission Owners. Nonetheless we, the PJM Board, recognize that several parties have appropriately questioned the specific allocation in this case. Accordingly, PJM will continue to provide technical analysis and information to affective stakeholders in order to help FERC with its ruling on this particular cost allocation and its cost allocation rules in general, closed quote. To date, PJM has been helpful in providing information for resolving the state agency's quote-unquote valid concerns and their quote-unquote appropriate questioning; and in that regard, PJM's preconference comments were helpful.

As evidenced from the preconference comments and other pleadings in these dockets, the Maryland/Delaware State agencies, Old Dominion and Eastern Utilities, recognize that a limited exception to SBD facts must exist. Stability-driven RTEP projects, of which there is only one out of more than 1,200 RTEP projects, constitutes a definable category. A cost allocation that aligns with economic benefits is feasible for these projects and is the only outcome that, in our view, would survive judicial scrutiny. A cost allocation based on economic benefits is capable of annual updates, just like the current SBD facts-based allocation. And in fact PJM tariff Schedule 12 B5 already requires PJM to conduct what's known as an LMP benefits methodology for cost allocation for certain other types of transmission projects. We would not be reinventing the wheel. A cost allocation based on economic benefits comports with the objective of ex-ante rules. If a when a projects falls with into the an undefinable category and economic benefits analysis would be conducted for the project in lieu of the SBD facts analysis. The process would be objective, the process would be neutral.

Our view is that a narrow exception to the SBD facts rules does not and need not swallow the rule. A DFAX based method may be appropriate for the overwhelming number of projects. So in answer to the Commission's two questions: Yes, there is a definable category. In the case of artificial island projects, it is a definable category of one. And in response to the is seconds question, can be develop an appropriate cost allocation method? Yes, I think you can look to PJM's tariff schedule 12 B5 for guidance on how to approach the economic benefits-based allocation that must occur with respect to artificial island. I look forward to further questions, thank you.

MR. LeCOMTE: Thanks, Bob.

Would you know if you would be following your presentation when you want to follow up on that? Thanks.

MR. KHADIR: Thank you and good morning everyone. My name is Esam Khadir, I'm from PSEG. Go to slide 2, please. For the sixth time I'm going to let you read line 2, talking about who PGMG is at your leisure. As the first question, PGMG believes solution-based DFAX is just and reasonable and is a superior, non-discriminatory, ex-ante cost allocation methodology. Power flow driven versus non-power flow driven is not an appropriate distinction. Underlined caution does not warrant any distinctions.

Slide 4, please. Some parties have suggested that the non-power driven nature of certain violations provide the reason for treating those violations differently. Some of them have singled out stability and short circuit issues as a basis of differentiation. There's no way for establishing stability issues from a voltage issue. The non-power flow distinction issues are the facts that the violations is a facility. However, voltage act problems provide examples of violations that's non-power flow driven in nature. Voltage reactive issues are one of the biggest drivers of the RTEP projects in PJM. Violations can be caused by solutions of power flow violations. For example, short circuit problems; the more you build, the more you have short circuit. A lot of the transmissions that you build are regional transmission, which makes the short circuit more than just a local issue. Short circuit instability allocations need to be addressed no differently than voltage or thermal violations.

Non-power flow violations cannot be pigeon-hold as localized concerns. If you take a look at voltage, which is on the power flow issue, you see that the project, which was a regional measure, is a voltage violation project. Voltage issues affecting east and central cases, those are 500 kV interfaces and also regional. So voltage could be regional. Those are the issues.

Artificial island, go ahead and go to -- those are two complexes that have stability concerns, both of them are on the 500 kV system. Short circuit issues: Those issues are caused by new transmissions, as well as existing transmission circuits and now generation. The transmission, the new transmission and previous transmission have short circuit issues.

Slide 6, please. Carving out categories from the solution-based DFAX will read the future reviews. If we take a look at the question that we're here for today, artificial island. The baseline for operational performance project, this is both system stability and high-voltage reliability issue. I can argue very well that the problem in artificial island is a stability problem, not a high-voltage problem. They can argue that is a high-voltage problem not a stability problem. The BLC project, the baseline reliability project that has risen a variety of reliability issues including several and short circuit projects, as well as the short circuit issues. The project, this is the project that has aging infrastructure as well as short circuit issues. Again, we can argue which one is which. The next project, it's a baseline that's a driven solely by violation short circuit. How would be address that one? Which category are we going to pigeon-hold it to?

Slide 7, please. Next project is multiple drivers as well as single drivers. The projects are not readily and easily categorized as others.

Slide 8, please. Solution-based DFAX is a superior cost allocation approach. PJM has had this DFAX. Problems with violations based approach include: Unmanageable from project of written a high number of violations; a local project we had 53 violations to start with, unmanageable to come up with the cost allocation violation DFAX. Overly cumbersome approach. Results may not necessarily be repeatable on an annual basis because violations could differ. The violations that you have today, a generator could come in tomorrow and completely erase that violation, or another generator could retire and that violation would go away. To adequately capture future violations of a future project and are not suited for a voltage or other issues such as short circuit or stability because those violations would require use of power flow baseline and we have to get proxies or surrogates in order to be able to analyze. The proxies would require exercises of engineering judgment and making an exact time. What it basically says is that if we're carving out short circuit and stability PJM, better allocation with violations of allocation, the violation based DFAX is not going to help because it's not a good or accurate measure.

Slide 9, please. Solution-based DFAX provide the nondiscriminatory ex-ante approach required under Order No. 1,000 while avoiding the problems previously encountered under the violation-based approach. It allocates costs upon commensurate benefits of VLC from our approach. It is annual and changes in beneficiaries over time.

Slide number 10, please. PSEG has already addressed an appropriate allocation with methodology for VLC and a northern engineering and an underlying docket. We are not covering the same ground now, but we do offer this deeper regarding the cost allocation for the artificial island project. I'm going to go a little bit more into the benefits for the artificial island project as it pertained to the Del Marva area where it is the primary beneficiary of the artifical island project. If we take a look at the map that we have in front of us, the yellow highlighted system that is the Del Marva area. And a couple things that you can notice there: The only times that the outside of Del Marva has are basically in the North and the orange or red lines are 500 kV, the greenish blue lines are 2 KB. So if you take a look, there are a million interconnections, primary million connections of the 500 kV at two points, one is the red line and one is blue.

Just a to give you a little bit of information on the Del Marva system: It's load is over 5,000 megawatts; it's served by two 500 kV transmission lines into two 500 kV stations; and it also has some load capacity due to kV lines in the North and one 138 kV transmission line. The Del Marva area has been subject to transmission constraints and congestion in the past, and still does. The Del Marva area has very old generation, over 30 percent of this generation is over 30 years old, high capacity -- sorry, with a high risk of retirement into the load and environmental regulations that we have today. The amount of generation that we have in Del Marva is less than the amount of load that Del Marva has.

If we go to slide 11, please. This slide shows the northern ties of Del Marva of the PJM. You can see a tie from the island, that's the artificial island, and another tie from Keeney (phonetic) to Rock

Spring. Let's take a look, the length of the tie between is 17 miles. The whole area is the artificial island area which has about 3,800 megawatts of generation. So if you take a look at the next closest station to there, it's either Orchard or New Freedom, Orchard is 28 miles, New Freedom is about 20. Orchard to New freedom has PSEG as well as Olympic and both of those companies has a lot of generation in their system, not highly dependent on the two areas as much as Del Marva depending on Red Lion. The other ties to Del Marva are the two ties to the north.

What are the benefits of artificial island project? Artificial island project has another high-capacity line into Del Marva five miles from the complex with 3,800 megawatts of generation, 3,800 megawatts of baseline generation is more generation than Del Marva. The tie consists of a transformer and 2 KB line into Del Marva. And the flow line would only be from artificial island into the Del Marva area; it's not going to go anywhere, the flow from Del Marva is not going to go to artificial island. The upgrade, a little bit closer to the Del Marva grade.

And with this new five-mile line comes a lot. And it's very clear that that line is only in the Del Marva area, as shown in the solution-based DFAX.

The reliability of the Del Marva customers would improve with that line. In a way, if we didn't have that line and you look at the electrical diagrams there, and if we apply the NERC minus 1 criteria which says you can outage one line, so if we take the Red Lion to Sandow and then you take the second line, and then we continue to Rock Springs, you'll have 4,000 megawatts of load and very old generation in the Del Marva being fed by two 30 KB circuits. This project would provide a very high capacity, some circuits tied to 3,800 megawatts.

MR. LeCOMTE: Could you get to your conclusion and comments? Thanks.

MR. KHADIR: Okay. I wanted to talk a little bit about the market efficiency analysis that the Delaware Commission had mentioned, but I'm not going to have time to do that. I hope that you give me a chance later on to talk about it. The other thing, too, the Del Marva Peninsula has separated from PJM and RPM twice before, once in 2010-2011 and the other one in 2012-2013. That means that there is potential for it to split again, which is a huge cost to the Del Marva zone; it happened. Having a line that is run from artificial island into Del Marva, it greatly increases the value of the capacity energy atmosphere limit of the zone, which subsets and avoids the increased capacity crisis.

In conclusion, there's no cause for the category cause-out of the solution-based DFAX as we saw with the EI and DLS cost allocation structure of the stability driven projects. Thank you.

MR. LeCOMTE: Thanks, Esam.

I'm note from those on the phones that I believe Esam's presentation, and I believe we got a presentation from Hudson up next, are posted on the Commission's website. Thanks.

MR. WOOD: Good morning, Jeff Wood. I'm from a company called Power Grid, Power Grid is the managing member for Hudson and Neptune Transmission Projects. We appreciate the opportunity to speak this morning. And we first say that we agree wholeheartedly with the comments that Amy and Mayer said. Rather than repeating that, I want to focus a little bit on what merchant transmission facilities are and how they're different and how they're not, what cost allocations have been decided for transmission facilities, and what the economic focus of that is on us if we start thinking about cost benefit discussions and whether or not solution-based DFAX makes sense for things such as a short circuit project.

Going to my first page -- and I apologize, I don't have page numbers -- but turning the page, each of

Neptune and Hudson are 660 megawatt HDCD facilities. They are capably physically of running bidirectional of PJM to New York and New York and PJM, and currently are only approved to run from PJM to New York. The control HDCD, Neptune has 660 megawatts, Hudson has 320 of firm transmission. Those are important figures because that's the basis of which RTEP is allocated on these projects. It's also what allows capacity it be purchased in PJM and sold across the line into New York.

Turning the page, I just wanted to give everyone a sense of what Hudson is. The foreground of this photograph is the Hudson converter station, and in the background is the PSEG substation. We connect to the PSEG substation shown by the whole line there at the 230 kV level. We convert that AC from DC in the white building, then it converts back from DC to AC and we transport it across to New York at 335 kV. It's important to note that we are interconnecting at the 35 kV level, and that has to do with a similar upgrade that we're responsible for building which is a Bergen line to 230 kV upgrade that was allocated to us.

To go to the next page. What are merchant transmission facilities? What are we not? We do not have any inactive customers, we do not recover our customer base. The only way we recover our cost is from the sale of capacity and energy across the line. So effectively the only benefits that we can ever garner to give us a bill to recoup cost is something that's going to reduce the cost of capacity and energy to PJM or increase the price of capacity of New York ISO, or allow us to sell more energy capacity across the line at the same spread, recognizing that if we seek to increase our SBWR we have to make another interconnection request, and if there are any associated upgrades with that we're responsible for these costs.

The other thing about a merchant transmission facility is we are economically dispatched. What does that mean and why is that? Because we look like a generator in New York ISO. We are competing with generators in New York ISO. If the price of power of PJM is higher than New York, we don't run. That's an important concept I think to consider when you talk about a flow-based model that's run at peek periods for determining benefits. History has shown we generally don't flow with those peak periods, and in fact Linden VFT flows in reverse, helping to solve the problem that's happening at peak time.

Let's skip two pages and go to the cost allocation. I don't think this is in disagreement anywhere, but there were comments made earlier is cost causation the right method for cost allocation? So if we turn to the pages titled cost allocations, I wanted to talk briefly about the specifics of Hudson Transmission. In that particular case we've been allocating slightly more than 300 million dollars in upgrade costs for work that was performed in PJM that came out of our interconnection studies to allow us to resolve 320 megawatts of FTWR's. The biggest component of that was the 380 kV Bergen transmission line, which just went operational November 30th. We've been using it for less than two months. Now, the tariff required that we pay a hundred percent of the costs on that because it was very easy to determine who caused the problem. That's the tariff; we agreed to it, we knew that going in. If you ran solution-based DFAX on that I suspect others would show benefits on that. But those are not the rules of the game, we understand that. But the causation is the method to apply costs to us; it should also be the method to apply to RTEP charges.

So I would offer to you that if at the point of time that we entered into our interconnection agreement, everything else in the PJM system was frozen the exact same way we were, we can't change without asking for an interconnection upgrade to the cost. If everything was frozen there would be no need for RTEP upgrades. The only thing you would need would be to reinforce and replace old expiring equipment. All the other RTEP is for expansions and changes that are happening in the system which we cannot constantly be causing since we're static. We can only change if we come in with another interconnection request.

So if we turn to the next page and look at the history of the cost allocation, at the time we joined the PJM system and made the determination, the business decision, to move forward on a merchant basis, the cost allocation was a hundred percent share. Hudson was 0.2 percent, Neptune was 0.4 percent of the entire load. We were able to make a reasonable determination at that point in time of how expensive could it be for us being a vendor of PJM and being responsible for RTEP cost allocation. We could make some absurd assumptions as to how broad the costs would be in PJM and we were going to get very small percentages. That clearly had to change. The 7th Circuit Court said that's inappropriate, Western Utilities were being asked to pay for costs that they were not causing. So there was a shift, there was a shift to violation-based DFAX. I believe that was an attempt to prior to allocate the costs to those who caused the problem.

Steve made the comment, it's very hard,

particularly with short circuit, there's no one specific costs, there's a bunch of people that could cause the problem. I can tell you one thing for certain that isn't causing the short circuit problem, and that's Hudson and Neptune; there's no way they're causing the problem. Steve mentioned there's a generator in New York that could be causing the problem; not across our facilities, we control the line, we don't bring those short circuits across, so there's no way those short circuits could be the result of us.

I also suggest that you run it without the ConED wheel, without us, without the FTWR's, the short circuit is going to be there, and indeed the upgrade is still going to be there. So we could not possibly be the reason from the need to solve that short circuit problem. For that reason, the DFAX method is clearly not the appropriate solution for something like a short circuit problem. We did talk about the economics a little bit on the MTF on the next page. On the right-hand side for this PSEG projects of what our cost allocation would have been if it was a hundred percent load ratio share. The two mailboxes are the cost allocation -- the center one is the PJM cost allocation of ConEd and the wheel, and then there's a question to have that determination made with ConEd no longer in the wheel, and it shows the cost allocation to Hudson. The bottom line is my attempt to make some gross estimates and take them for what they are as to what the annual transmission revenue requirement would be that Hudson would be billed from PJM, and that number ranges from 18 million to 100 million dollars, annual number. In order to recoup that cost, the price of capacity of PJM would have to decline by 153 dollars per megawatt day to $850 per megawatt day for us to recover those costs that we would be allocated to.

I can tell you one thing for certain: The nature of this RTEP cost allocation absolutely makes it impossible to mobilize capital for merchant transmission projects and it also puts the shareholders in my two companies in a position where they absolutely have to seek any means they possibly can to just try to save their existing investment. Amy brought up on the next page some concerns; I just want to raise questions about these. From my comments here you can see that I don't think that solution-based DFAX at all is an appropriate allocation for these types of projects in merchant transmission. But I also just ask general questions: On the one percent de minimis rule, if there's a TO that's shown to use 100 megawatts of facilities and we're shown to use six why do we get costs and they don't? And then when there's a gross of that, we actually have to pick up their cost? That is hard for me to understand the rationality on that. And then if we look at the netting on situations there and de minimis all mixed together, you could have say a 400 megawatt facility, maybe Hudson got allocated 5 megawatts and TO got allocated 45 megawatts. If that TO is GPNO, I got responsibility of 10 percent of the project. If that TO is 80 P or PSEG, I now have responsibility for 80 percent of the cost. Someone has to help me understand why my benefits went up 10 times in that second scenario.

The last point, and PJM made the comment that we're looking for differentiation in terms of how costs are applied to us, and the answer to that is yes, I think it's appropriate. I think we are dramatically different than any other TO and I think we are dramatically different than load. We just function very different, and because of that I'm not sure one methodology will work for everybody.

I look forward to a very productive discussion throughout the rest of the day and thank you very much for the time to give my comments.

MR. LeCOMTE: Thanks, Jeff.

Mark?

MR. RINGHAUSEN: Thanks. This is on behalf of the cooperative or ODEC. I want to thank the Commission and staff for the opportunity to speak to you today. The issues that the Commission has identified for discussion are important for ensuring that the costs for new transmission facilities within PJM are reasonably allocated. Resolving these cost allocation concerns is also important to promoting greater cost certainty in the greater mechanism used within PJM. We would like to commend PJM for submitting its matrix well in advance of this technical conference. The PJM matrix provides a very useful framework for discussing issues identified by the Commission in its endeavor of the 24th order. By way of introduction, ODEC is a generation and transmission electric cooperative based in Richmond, Virginia, serving 11 Transmission Owners in Virginia and Delaware. ODEC is generally considered a transmission-dependent utility of PJM, although we do own a small amount of transmission utility in PJM and thus ODEC is a transmission owner. As a PJM transmission owner ODEC participated in the development of the current PJM cost allocation, including the use of solution-based DFAX, and ODEC continues to support those methods when they were filed with the Commission.

I wish to emphasize that ODEC believes that the solution-based DFAX continues to produce reasonable cost allocations for the overwhelming majority of PJM RTEP projects. Since solution-based DFAX went into effect in early 2015, however, we want to see a small number of RTEP allocations produced by solution-based DFAX do not reasonably align with the customers who can expect to benefit from those RTEP projects. ODEC was directly impacted by these solution-based DFAX when PJM agreed to several RTEP projects with the artificial island in New Jersey.

The artificial island projects are designed to resolve outstanding generators stability issues in Hope Creek and Southern New Jersey. Yet over 90 percent, as mentioned earlier, are 275 million dollars in allocation costs would be allocated to PJM Del Marva zone. Because ODEC did approximately 20 percent of the loading of Del Marva zone, ODEC will pick up significant portion of the allocation of the project cost under solution-based DFAX methodology. RTEP projects, for which solution-based DFAX has not produced reasonable results, all fall within a small category of projects that generally do not address thermal- or voltage-based reliability violations.

PJM matrix shows that for very few projects, six to eight percent fall within this category.

Planning in PJM generally is based on reliability planning criteria to detailed power flow models, a.k.a. solution-based DFAX, to an allocated cost of an RTEP projects through a flow-based model process like the defects that are logical when the project resolves a criteria violation identified by these same PJM power flow lines. Hence you have the length between the model and the violation. RTEP projects address other than flow based or thermal -- voltage violations identified through PJM model process, there is not necessarily any relationship between the need for the upgrade and the customers who should use them by that project.

Looking at the artificial island project in particular, the primary component of this project is a 230 kV transmission line, as mentioned before by Southern New Jersey and the State of Delaware. This 230 kV line will help resolve the generator issues at artificial island, that has been clearly stated by PJM, but is not required to resolve any thermal or voltage reliability criteria violations that might be caused by load growth in the Del Marva zone since there is no violations from the Del Marva zone that may be resolved by this 230 line. Because the stability problems at artificial island are attributed in part of limited transmission pass at artificial island area, it's only been inevitable that solution-based DFAX would simply advocate the cost of a new transmission line out of artificial island to the PJM zone in which the new line happened to terminate. So if the line had gone to D.C., the D.C. folks would have been the cause; if it went to New Jersey, New Jersey people would have been paying the cost. It's just the fact as solution-based DFAX is utilized.

Solution-based DFAX do not signify any significant benefits from the Del Marva zone from the new line that could justify the cost allocation. The only question raised by the Commission's November 24th order is where the projects where solution-based DFAX may be justifiable is found, and ODEC believes it clearly is. The problem with solution-based DFAX to allocate RTEP project cost arising from the disconnect between the reliability planning driver for the project and the use of the new project as majored by the solution-based DFAX. In other words, the categories for projects in solution-based DFAX cannot be relied upon to provide reasonable cost allocations which could be defined based on planning drivers, which are clearly transparent in the PJM planning process.

PJM matrix itself is evidence that PJM can readily break out RTEP projects by reliability planning drivers. PJM project drivers have also provided stakeholders in the PJM planning process particularly through PJM transmission expansion in the advisory community. Looking at the seven reliability projects driver categories included in the PJM matrix, ODEC does not believe that it's reasonable to rely on solution-based DFAX for RTEP projects required by: (1) stability violations; (2) short circuit violations; or (3) storm hardening. Solution-based DFAX may or may not resolve on just and reasonable allocations for operational performance, another category in the PJM matrix. And that depends on the nature of the line operational problem. Therefore, the operational performance identified by PJM under operational problems is not a problem that arises to the significant violation; then solution-based DFAX isn't over.

However, if the operational performance upgrade are driven by a non-flow based criteria such as stability concerns are the project should be considered for alternate cost allocation methodology. That leaves the Commission's question on whether an alternate just and reasonable ex-ante cost allocation methodology could be established for the categories and facilities where solution-based DFAX could not be relied upon. That would require a conference on whether alternate methodology or methodologies can be developed.

With generators stability problem like artificial island problem, we need to allocate the cost based on the relative proportion of economic benefits that result from the stability upgrade since the primary benefit of the project is to increase the availability of the generator's output to provide capacity and energy in PJM. And Mr. Weishaar did a very good job of narrating the economic benefit of the artificial island. So I want to thank you and I look forward to further discussions on this topic.

MR. LeCOMTE: Thanks, Mark.

I want to thank all of the panelists on their presentations and all of those who submitted their preconference comments. The staff is going to have questions based on these comments and the filed preconference comments.

I originally put into the agenda a break for 11:40. We're a little bit ahead of that. So I'm going to take a break now; it's not a longer break, just an earlier break. So I'll come back at 11:40. Thanks.

(Whereupon a short recess is taken.)

MR. LeCOMTE: Okay, if we can get started. Two things I want to ask: I've been able to turn my volume down on the phone, but the feedback I hear is that people are still either typing away or shuffling papers, and it's disruptive to those who are trying to listen. So please, telephones on mute if you're listening.

And the other is for the panelists. I understand that folks on the listen line are having a hard time hearing, so make sure you hold the microphone in front of you. It gets difficult as we speak without the mic in front of us, so if I can ask that we try to remember that as you're speaking.

Okay, and I actually wanted to follow up on some of the comments that were made earlier, especially from PJM, and I think the notion of the cumulative effect of some of the contributions to a short circuit concern. And I think that that was helpful. I know we had a little bit of a followup from the transmission owners on the appropriate -- and why the solution base would be appropriate for addressing what seems to be a cumulative problem. I want to see if there's any followup on that.

And then I suppose I want to see if I can understand that theory or those comments in the context of a stability problem and whether -- especially as you, Steve, had pointed out -- the notion that many of these are resolved at the generator interconnection analysis, so.

MR. HERLING: Sure. And similar to short circuit, but even to a greater degree, every stability problem that we have ever had to my recollection -- actually, there were two others that were you'd in the RTEP but they were resolved with very minor adjustments to control devices within the generating station, so they're hardly worth talking about. But every other stability problem that we have ever identified turned up in a generator impact study to the interconnection study. So it's even more skewed toward not turning up in the RTEP.

This is clearly a unique situation; whether it will ever happen again is really hard to venture. But it's a combination of things which I couldn't even begin to dissect everything's that has happened in the last 10 years that may have led us to a situation where we had to balance either the inability to control voltages with the stability of the station, three large nuclear generators, and it would take a lot, a lot of work to back up in time. It's easier to see with short circuit because there are really decreased changes to the grid that add short circuit duty at a particular location with the stability at artificial island. It would take a lot of work for us to go back in time and try to identify every change that has taken place in the last 10 years, five years, whatever, and say that made the problem worse, that made the problem a little will worse. And we haven't attempted to do that, okay.

With the short circuit, it would be a lot of work but it would be more straight-forward because you would know what the look for. Transmission lines will add short circuit duty out of location, generators will add short circuit duty out of location. Reconfigurations, Esam talked about closing the bus tie at Hudson, that will clearly add short circuit duty at a particular station. Go ahead.

MR. LeCOMTE: Okay, and so that gets us a little bit into the causal, what's causing some of these problems. I think to the extent so we've accepted the solution-based cost allocation mechanism and it identifies beneficiaries through the use of facilities. So I'm trying to keep us moving in the understanding of beneficiaries.

MR. HERLING: That's the challenge. Cost allocation is not supposed to be -- what's the word that you use? -- commensurate -- that sounded like a PSEG person, just to be clear. Roughly commensurate.

MR. LeCOMTE: Somebody without the microphone.

MR. HERLING: Cost allocation is not intended to be roughly commensurate with use. It's not intended to be roughly commensurate with who caused the problem. It's intended to be roughly commensurate with who benefits, okay. So you have to decide what constitutes a benefit. And obviously use of a facility, there are clearly benefits associated with the benefit to use a facility. Now, people have talked about the fact that you don't actually get to chose which facility you put flow on, but the fact that the facility exists and you are able to put flow on it is a benefit.

Now, the argument that we used to make when we had violation-based defects was that the existence of a violation of reliability criteria puts customers at risk; the elimination of the violation is therefore a benefit to those customers. So the argument back in the day was that the people who caused the problem are benefitting because the system is now reliable because we have fixed it, okay. So there are ways to attribute benefit to various things that you can measure, okay.

Let's face it, there's lots of other benefits. The general reliability of the entire grid is a benefit, okay. The jobs that a project creates, that's a benefit but it's not one PJM is in a position to measure.

MR. LeCOMTE: So what do you think is an appropriate way to identify beneficiaries for these, yours was unique, but a stability problem or maybe a short circuit problem?

MR. HERLING: Right. I think a lot of people said some of these things already, so I will characterize it perhaps a little bit differently. The benefits will evolve over time, they will change. That's one of the benefits of solution-based defects, the users of a facility change over time. Solution-based DFAX is readily calculated year after year so you can measure those benefits as they change. So the resolution of the problem on day one will -- what's the best way to say this? -- that benefit fades over time, okay.

If you look at artificial island, 30 years from now the stability benefits will probably no longer be there because one or more of those units will very well be retired. So the stability problem will have gone, the line will still be there and will still be used and useful.

MR. LeCOMTE: And you would say the flows may be significantly different?

MR. HERLING: They may or may not but they're readily calculable. The point is that the initial benefit of solving the problem fades over time.

So is there a way to calculate the benefits of solving the problem? There may very well be. When you look at a thermal overload, I would argue that the benefit of solving the problem and the uses of the facility are largely the same. The people who cause flow from A to B are the ones who are going to be using the new facility. You build from A to B to solve the problem, it's largely the same. It won't be exactly the same, but it's largely the same.

With stability and short circuit, that's a trickier proposition. Number 1, you have to kind of come up with a methodology for measuring who those beneficiaries are, and then you have to figure out a way to weight those benefits against the benefits of use. And that weighting will change over time. On day one it may be more toward solving the problem. 30 years later it may be entirely on who's using the facility.

MR. LeCOMTE: So if I were to look at the matrix that you've given us, and while I know there are some stakeholder issues identified for the different groupings that you've provided, that by and large the solution-based is supported for flow-based or thermal and voltage type reliability concerns. And you've identified several groupings of reliability concerns, okay: The short circuit; the stability type issues; aging infrastructure. What would you think of identifying beneficiaries for this other group that you've classified in the matrix?

MR. HERLING: It would be my position that thermal and reactive I think are perfectly well-handled by the solution-based DFAX. I believe the most operational performance issues will also be well-handled because they're typically either thermally related or voltage related. I think aging infrastructure is very well-handled by solution-based DFAX. So it really gets down to issues where the nature of the problem is different. And short circuit and stability are the ones that we've been talking the most about, we have categories of one in each case.

But then you get to a situation where you have to decide if you're going to take on wanting to solve this issue for a category that may have one project ever, okay, then you have to figure out how you measure that benefit of solving the problem initially and how do you weight it against the evolving use of the facility over time?

MR. LeCOMTE: Great. I think I've heard from several of the comments on an economic benefit analysis. Give me some comments on that.

MR. HERLING: Sure. I don't know that that would apply to short circuit, I would have to think a bit about it. But I'm not sure it's going to apply to short circuit. For stability there were two market efficiency analyses that were performed. Market efficiency analysis could be used to identify the parties that are affected by the stability of the plant, okay. The dollars themselves, I'm not sure -- it's not a traditional market efficiency problem. If you look at artificial island, the likelihood of one of those units being forced off because os a stability problem is very, very small. So the dollars that would actually be realized over some period of time will be small, but they are analytically a good way of pointing to the buses and the zones that would be impacted by the stability of the plant. The further away you get, the less market efficiency benefit would be realized, and coincidently the less impact there would be of the stability of the plant.

If you look at Atlantic City Electric, which is right where the plant is, or Del Marva of Pico, those are the zones closest, they would have the biggest problem if you had a stability problem. And in the short circuit analysis that was referred to, that's where you see the biggest delta in the LMP's, okay. So there are analytically ways to establish which zones are most impacted by the stability. The challenge again is how much weight do you put on that when you compare it to the use of the facility that has been built to resolve the problem.

MR. LeCOMTE: Right. So I know in the PJM tariff there are provisions for economic cost allocation. Maybe you can tell me what you think the basis would be for looking at economic benefits of reliability projects?

MR. HERLING: The provisions that are in the tariff today or the operating agreement are based on projects that are justified on the basis of market efficiency. There are no provisions to say if you have a line, form a liability, and it happens to save a million dollars in congestion, that's a coincidental benefit, and there is no provision to include that in the cost allocation for the facility. That's not to say that there couldn't be. The challenge is how much is a million dollars of congestion worth compared to eliminating a thermal violation of NERC reliability standards? There is no direct relationship, so you just have to pick up and it will be arbitrary.

If a project is approved by the PJM Board because by itself it satisfied the market efficiency standards, then there's a method for allocating those costs. And that's pretty straight-forward, and it is based on where the LMP's are reduced. And if there are RPM benefits, there are various ways of looking at the benefit of the project. But today there is no way to just grab those coincidental market efficiency benefits and attribute them to the cost allocation.

MR. LeCOMTE: Okay. I note there are quite a few cards up, so I'm going to let some other people respond to that.

I do want to remind people that -- and I appreciate all the comments that have been filed and the comments that we've heard today, and I think we have a very good understanding of your perspective. I want to make sure we stay on the point we're trying to understand here, so. With that as my -- let's try to stay on point.

Mayer, I think you were first, and then I'm not quite sure, I lost -- but I know Mayer was first on his card.

MR. SASSON: We'll all have a chance.

MR. LeCOMTE: Hopefully we'll all have a chance, yes.

MR. SASSON: I just want to say that we think that these issues are rare, and we've already said why they're rare. It's very rare that a short circuit is being resolved with a transmission; it's very rare that storm hardening is being resolved with a transmission; the transformer. So given that these are rare, we try to answer the two questions that you asked in a very direct manner. These are rare but they're in a different category, right, there's no overloads here. And if they're rare and they're in a different category and we know where they are, what happens what Peter was saying the "where", the zone, that's where you should cost allocate it.

And so you have an easy answer to both questions, something that is very rare. Now the question has come up: What happens in the future years? Well, the future years are really not an issue because this line was not built for that purpose. If we're going to look at future years we should look at every single line in the system, who's using that line. So I don't think that is the issue, I think the zone and we're done with it.

MR. LeCOMTE: I am going to let some others, but let me just ask: Okay, to you Mayer, so you have indicated where. Then tell me what you think about where as it relates to stability-related issues?

MR. SASSON: In my opening remarks I said if we have a stability violation it's because Steve, these people, Steve's people, analyzed a stability situation and said, "Ah, if something happens, we have in the system, some units, even if it's rare, some units are going to lose stability." We have a stability violation, there's a rule that says when that happens you got to do something about it. Sometimes you can just do controlled, which is what he said. It should have been caught in the connection process, he said. So very rare you're faced in -- maybe never comes up, as Steve said -- you got the transmission issue to address the problem. But once you got a transmission line to address the problem, then where are the units that felt the stability issue? In the zones where the units that felt the stability problem, that's where you should go. And that's the "where."

MR. LeCOMTE: Okay, thanks.

Jeff or Amy?

MR. WOOD: Just I hate to go back a little bit. I want to talk about short circuit and comments he made right before we broke. I want to clarify the record a little bit. Esam's comments were on the short circuit that Hudson was causing the problem. And I would acknowledge that when we were studied we caused some short circuit problems, but we paid for all the solutions at that time to resolve the problem. We spent roughly 30 million dollars to entirely build out a new substation for them at the 80 kV level, probably creating a little bit of headroom in there. And this is before VLC was ever even contemplated.

MR. LeCOMTE: I appreciate that. Did you have a comment on point or do I go to Amy?

MR. WOOD: Go to Amy.

MS. FISHER: I just have two short comments. The first is that PJM has several formulas in Schedule 12 which have a series of different pieces that need to be accumulated together, I'm thinking of the multivalued projects, which determines beneficiaries and how different cost allocations are going to be added up and allocated. So there's the public policy piece, that goes to the state; there's the market efficiency piece, that goes in the accordance to 1.25 to one formula; and then there's the reliability piece which is allocated based on solution-based DFAX. This is not a one size fits all, there's no reason why you can't count up all the beneficiaries in each of their different ways and cost allocate. Yes, it's a little more complicated, but the alternative is simply to have a formula that doesn't work for ex-ante purposes.

And I would just make one more comment,

which is the statement that Steve made that solutions-based defects under Schedule 12 measures use is just not a true statement. It measures use and then it has special savings rules which change the allocation so that it no longer measures use.

MR. LeCOMTE: Thanks.

Frank or Takis. Mic, please.

MR. LAIOS: Takis Laios, PJM Transmission Owners. Two comments: The first one, going back to the short circuit discussion about if we're going to focus on the parties that incrementally pushed the short circuit over the top then, we talked before lunch about what you do about the parties that chewed away at that capability creating the situation for that incremental situation to occur. And then once you put the solution in place, there would be others parties in the future if you hadn't put the solution in place that would have contributed to the violation. So if you don't have the metric to measure their use of the solution, you are creating a free ridership situation there. So the solution-based DFAX approach addresses all that.

Again, any causation type approach would be a one-time calculation, you have to decide what you do to the parties that came before the incremental violation was created, and then the parties that come later that benefit from the fact that the project was there would have contributed to that short circuit problem that are not paying for that project, so you're creating a free ridership.

Regarding the economic issue, first of all, the projects that we're talking about here are reliability projects. So the question is: Why would use that for reliability projects? If you do it for these so-called special set of projects or unique projects, wouldn't you be compelled, then, to do it for all of the reliability projects? So essentially all reliability projects would need to go through an economic calculation.

And the final thing with the economic approach is it's still a one-time calculation, it's not updatable each year. It's similar to the violation-based DFAX approach, you do that calculation as a one time and you cannot revisit it. So consequently in that respect it's not any better than the issues we come to with violation-based DFAX, it's not updatable. So I appreciate that.

MR. LeCOMTE: Thanks.

Bob, did you have a comment? Sorry to whip the mic around the room.

MR. WEISHAAR: Yes, thank you.

A few comments. (1) On the total benefits associated with the project, when PJM ran its market efficiency study for artificial island it showed that the total LMP, just LMP -- related benefits of the project, were around the order of 169 million dollars, and that was just a one-year snapshot. So when you're looking at sort of return on investment and cost benefit ratios over time, and looking at an estimated cost of 275 million dollars on the artificial island project, and if you take an economics-based allocation, the zones can look at this on a return-on-investment-type basis where they get the benefits associated with the cost responsibility for that particular project.

When we looked at -- we have two issues today: One is the definable category, and I think it's getting pretty clear and clearer that artificial island falls into a definable category. It is a stability-based project, there is one of 1,200. The second issue is a little more challenging, and we thought about what is the appropriate approach for cost allocation? It is a reliability-driven project, but coming up with an objective quantifiable, independent, neutral approach for quantifying the reliability benefits is extremely difficult. So we got to sort of the next step of what are the other options? We looked at the Con Edison approach of a load ratio share. That load ratio share in the context of artificial island would likely result in a hundred percent of the costs of artificial island being allocated to the PSEG zone, which raises equity issues in the reverse. Because when you look at the LMP benefits, only 16 percent of the LMP-related benefits inner to the benefits of the PSEG zone. So you would have almost the reverse of what the Del Marva zone is facing today. So that raises its own set of equity issues.

Another option would be to allocate some cost to the generators that are directly benefitting from the line. The line will allow generators to produce more energy; you can measure that, an incremental amount of energy, the same generators went through interconnection studies over the past 10 years and didn't receive any allocation of additional upgrade costs or interconnection costs associated with those, even those issues that were present during that time period. So another option is to allocate some or all of the costs to the generator in that area that will benefit from increased output. That is not a direction that the Commission has taken to date; nothing precludes the Commission from taking that, but it's not an approach that the Commission has taken to date.

So we came to option 3, which looked at that LMP-related benefits, and to the extent that PJM can quantify them, any capacity-related benefits are proposing to allocate the costs of the artificial island project based on those economic benefits. These are studies that the methodologies for which are specified in Schedule 12, and also in Schedule 6 of the operating agreement where PJM already has formulas in the tariff for determining the capacity of the energy-related benefits of a particular project. So it's administrable; it's capable of being done by PJM; it's capable of being updated on an annual basis just like SBD facts. So you can get to an outcome here where our touchstone, our ultimate objective, is benefits have to be roughly commensurate with costs.

MR. LeCOMTE: If I could -- and I will get back, Frank and Esam.

But following up, Bob, so you would advocate something like that for in the case of the stability related to the artificial island. Tell me what you think of that approach for some of the other type of violations, storm hardening or short circuit. Is there an appropriateness in those types of violations?

MR. WEISHAAR: We have not taken obviously a thorough look into the short circuit issues because what we're facing in the Del Marva zone is a stability-based project. So we have not taken a position, I think that's for the other parties to discuss and address.

MR. LeCOMTE: Sure.

On the way back to Frank and Esam, if I can stop at Steve and ask him to respond to that since the mic is going by you, Steve.

MR. HERLING: I think we're going to need to clarify some of the market efficiency analyses that is being discussed. A traditional market efficiency analysis, when we look at a new transmission project, would be to model the system with the line in place and without the line in place; and we did perform that analysis some time ago. I don't remember the numbers, but I'm fairly certain the numbers that Bob was referring to was related to a market efficiency analysis that Delaware specifically asked us to perform, which was to compare the system as it is today but with one nuke turned off to the system in the future with the new line and all three nukes running. The premise being that without the solution the probability of one nuke needing to be turned off would be increased potentially over time. So the large deltas that were observed were as much or more a function of one of the nukes being off as they were of adding the line to solve the stability problem. So that is not a traditional PJM market efficiency with a capital M, capital E, analysis. It is a means of identifying certainly the LMP impacts of the stability of the unit.

MR. LeCOMTE: For what was specified?

MR. HERLING: For what they asked for. So clearly the stability impact of the nukes is reflected at least in some fashion by the LMP impacts of turning one of those units off. I won't argue with that, okay. But that's not a traditional market efficiency analysis as we would perform it under the operating agreement, okay.

Now, to your other question, if we were to start running market efficiency analysis to look for the ancillary benefits of every reliability solution, first of all, that would be a tremendous amount of work. I'm not sure to what extent it would show us a different set of beneficiaries than the parties who are flowing in the direction of the new line anyway. Today we do, with the new cost allocations, an analysis to show how many hours the flow is in one direction versus the other; that's part of the solution-based DFAX analysis, it's essentially a weighting mechanism. If the flow is 50/50, 50 percent north, 50 percent south, then we attribute benefits at both ends of the line equally. If it's 90/10, obviously the primary direction of flow is where most of the benefits are. So we do that analysis but it's based on the system as it exists moving forward to, I think it was Takis' point earlier, if we were to try to do a traditional market efficiency analysis where we actually wanted to see the benefit of the line itself, that would mean removing each line that we have approved over years and years one at a time and looking at do you unwind the system to the conditions that were in place 10 years ago? That would be an enormous amount of analysis. So I wouldn't suggest that that is doable in any reasonable fashion on a repeated basis. Somebody made the comment that we could do that analysis; I don't think that's possible.

MR. LeCOMTE: Thanks.

If I could get comments from Frank. I appreciate you holding.

MR. RICHARDSON: Thank you and sorry to move back a little bit. You started off with some comments from the merchant transmission owners. The merchants have made quite a bit of the fact that they're different, they need to be treated different, they need special rules, it's a different context for them. And I think it's really important for us to understand that that question has been answered by FERC. And the PJM transmission owners in executing the cost allocation we have to follow the FERC order, it's Opinion 503 maybe, (a) I think. But that opinion basically says when it comes to the merchants they need to be treated like any other zonal load.

And so when it comes to cost allocation, we do not treat them separately because the FERC order says that's how they need to be treated with respect to cost allocation. So we have had prior discussions with some of the merchant transmission when we put these cases into abeyance: We met with them, these are things that the transmission owners considered, how special can they be treated. And the answer is not too special according to that order that came out from FERC. So I think we need to understand that the current cost allocation reflects what that order tells us to do with cost allocation.

MR. LeCOMTE: Thanks.

Esam?

MR. KHADIR: Thank you. I just want to make a couple points regarding the market efficiency analysis that the Delaware Commission had asked PJM to do. The Delaware Commission has regarded the issue, and the scenarios are basically unrealistic scenarios. For someone to assume that one of the selling units can be out for a whole year, that's -- I've been working with PSEG since 1976, about the time that those units were put in Commission. And up until now I have not seen one of those selling nuclear units out for a year was of stability issues, and I don't believe that they will be.

Now, I'm also in charge of running the stability analysis and coming up with operating guide for those units. The only time that we even reduce the output of those units is when there is a transmission line out. And we do not take transmission lines out with three units in service; we wait until one of the unit is doing refuelling outage and then we take that line out at that time. And when you have two units operating you don't have to reduce anything. So the results from that analysis is totally unrealistic.

Now, PJM, as they were doing their comparison, the proposal comparison analysis for artificial island, they performed a market efficiency analysis according to the assumptions developed by TEAC (phonetic). And reviewed those assumptions with TEAC. The results from that market efficiency analysis shows that there is about 90,000 to a million dollar worth of benefits over 15 years, and all of that 90,000 to a million dollars, a percentage of that 90,000 to a million dollars, were to the Del Marva zone. Now, that is real assumptions that we use to develop market efficiency, the best case that we use to develop market efficiency results, and that's the results that you should be using.

One other thing is you're going to be looking at benefits you need to look at the capacity benefits also to the zone. So that additional line from Salem (phonetic) to Del Marva would provide huge increase in the CETL (phonetic) for the capacity transmission limit for Del Marva that would prevent it from splitting in the future. And knowing how all the generation is there, that is a very potential scenario.

MR. LeCOMTE: Thanks, Esam.

If we could get the mic over to John, please.

MR. FARBER: Thank you. John Farber, Delaware Commission staff.

If I could just briefly respond to this issue that's coming up today in terms of it's acceptable to impose the solution-based DFAX and suspend the requirement for roughly commensurate benefits because over time somehow the benefits will inert. And I find it hard to accept that there are characteristics in the Del Marva zone that would somehow shift that 99 percent cost responsibility to the artificial island facility any appreciable amount over 30 years.

And I think it's patently unfair to impose on the Del Marva customers the requirement to pay roughly a 30 percent increase in transmission costs solely on the basis that to pay those costs for an un-determinative amount of time, whatever the transmission owners decide is appropriate --

MR. LeCOMTE: John, I understand you positio, and I'm trying to follow up on this. I want to move onto some other questions, so.

MR. FARBER: Okay, it would be unfair for the Del Marva zone to accrue this cost over time.

MR. LeCOMTE: I understand, I read those positions.

Steve, I got another curiosity for you as we talk about the reliability concerns, and especially we talked about the allocation of short circuit and the majority, the vast majority, to the zone. And I think, if I understand correctly, those are somewhat discreetly identified reliability concerns where you can address the concern. To the extent we have -- and you've identified in the dockets that you have under short circuit a short circuit problem, I suspect that that's a -- short circuits may be the primary driver of the project, but that there are other reliability issues that are being addressed in that project in particular. But I want to talk about it in a generic sense.

MR. HERLING: Sure. That project, by its design, obviated the need for a number of smaller projects that had already been identified for other reasons. And then, honestly I'd have to go back and pull out what each of those were. The project itself was designed to solve the short circuit problem. It was essentially a secondary benefit of the project that it would then eliminate the need for certain other projects. So you're correct in that characterization.

MR. LeCOMTE: And to the extent that, for the majority of short circuit-related, that are allocated -- well, I think you said they were -- particularly either addressed at the generator interconnection study or that they were under the thresholds and allocated to the zone.

MR. HERLING: Correct.

MR. LeCOMTE: So in that sense, can you comment on, then, the appropriateness of the DFAX for what generally doesn't seem to be allocated under that mechanism?

MR. HERLING: Well, we don't attempt to establish any DFAX for those problems. You can't realistically perform -- I suppose you probably could, I'm not sure what it would tell you, for replacing a circuit breaker. But because the allocation is to the zone, we don't actually perform the calculation; there's no reason to. When we have a single circuit breaker that needs to be replaced and the cost is $300,000, because we know the reallocation is to the zone there's no reason to even attempt a DFAX calculation. It's only -- this is, as I said, the first time we've had to do it and it's because the solution was in a line. And in particular now we have a DFAX calculation that's based on the use of the solution and is really divorced from the nature of the problem that required the solution.

Years ago if the same thing had happened there would not be a violation-based DFAX that could be applied to a short circuit problem. So I can only tell you I don't know what we would have done if the same problem had occurred 10 years ago. The rules would not have provided for that situation.

MR. LeCOMTE: Thanks.

Mayer, did you have a comment, please?

MR. SASSON: Just a very brief comment, Ron. And your questions were more on short circuit.

I want to go back briefly to storm hardening questions. And the fact that if you try to apply solution-based DFAX to that -- which has been done -- you get results, somebody already said "strange", but it's more than strange. You fix a substation, you build some lines, those substations have loads, and it turns out that the owner of those substations and serving those loads actually paid not even one dollar, not even one penny for it. So it turns out that you apply the method and it turns out that Con Edison and Linden would pay a hundred percent of that, and yet the owner of the facility, the zone where that facility is, is allocated zero dollars. And that cannot be. That's why I go back to the: It's the zone that needs to pay, that's the zone that has the benefit.

MR. LeCOMTE: Thanks.

Steve, if I could turn back to the matrix that you folks provided. Could you maybe clarify for me the distinction between real-time operation concerns and stability?

MR. HERLING: Which category was this?

MR. LeCOMTE: There's actually two separate categories in the matrix that you provided. One that provided stability, and there was one project; and then in the matrix there was a real-time operation concerns, they were about 50 projects that you identified in there.

MR. HERLING: Yeah. Operational performance is a category that we use when we have repeated operational problems that, when you study them in a planning case, they don't actually manifest themselves as a violation of NERC planning standards. But, for example, we have -- I can never remember what the acronym is. We have an operational procedure that is essentially it's a local load relief procedure where we have to be prepared to shed load for various operational circumstances. If that happens once we deal with it, if it happens dozens of times in a period; that's obviously an indicator that we should do something to resolve the problem through planning even though there may not be a violation of planning standards. So we use the operational performance category to review operational circumstances between planning staff and operating staff; identify things that are repetitive in nature; we bring them to our transmission expansion advisory committee; we review them. We then pursue a solution.

MR. LeCOMTE: As I understand, the allocation methodology you've identified in the matrix would be the solution-based DFAX?

MR. HERLING: Correct.

MR. LeCOMTE: So for those types of operational concerns the beneficiaries are appropriately identified through the solution-based DFAX?

MR. HERLING: I'd have to go back and look at all of them. But I believe most, if not all, have either manifested themselves as flow-based where we had to build a line to solve the problem, or voltage-based where similar to a voltage criteria violation, even if the solution was to at a reactive device, we could create the same type of surrogate through a line or an interface where the flow is a good indicator of the nature of the problem and therefore a good basis for cost allocation. So most operational performance issues look like either thermal overloads or voltage problems, and therefore the cost allocation, it kind of makes sense to do it the same way.

MR. LeCOMTE: Why wouldn't stability fit into that operational concern?

MR. HERLING: Well, it could. The nature for a stability problem is that for a particular fault that you apply on a system, the power plants, the generators, will swing and trip off the system because they lose synchronism. In the case of artificial island it was a combination of issues where if all of the units were running and we saw operational situations where we had high voltages, we would have to change the reactive output of the units which would move them into a condition where they became unstable. So you were fighting one operational solution against another. And ultimately we pursued a solution of a transmission line to improve the stability. The original nature of the problem is the rotational inertia of the generators; they were unstable for certain faults. So it's not like an operational performance issue which is related to flow two-load in an isolated pocket that looks just like a thermal overload and you can treat it for a solution; for cost allocation pretty much the same way.

Stability, it's just analytically unique compared to voltage or thermal overload problems. You may end up solving the problem with a line, but when you then do -- if you're trying to attribute benefits, the use of the line is certainly a way to measure some of the benefits of solving that problem. The discussion we had earlier, though, got to the issue of initially just solving the stability problem there are probably some benefits that are not being captured by the use of that one single line that you have now built. That's really the discontinuity, is how do you weigh the benefits of solving the stability problem with the benefits of having a new line? And some of the things that have been said are certainly correct, that that line creates in the case of artificial island another feed to the Del

Marva peninsula. If there were to be price separation in RPM that line would provide a significant benefit. But there are also benefits associated with resolving the stability problem, and those are not being captured, at least in total -- they're captured in part -- by the use of that one facility.

MR. LeCOMTE: To the extent that you -- and correct me if I mischaracterize -- the operational way that may be flow to the load as opposed to instability, is that then flow from the generator? Is that --

MR. HERLING: Well, stability problems, I described them in the table as being somewhat radial in nature because you have a cluster of generators the energy has to get out to the load. And you can look at stability as if you drew a circle around the plant it's the strength of all of the outlets to the rest of the system that determined the stability of the plant, among other things. But the strength of the transmission system determines the stability of the plant. So it is kind of a 360-degree outward phenomenon.

MR. LeCOMTE: And did I hear you make comments previously related -- because I'm -- to the extent I understand your comments now on stability and the outward nature, is this something that's generally addressed, though, at the generator interconnection analysis or studies?

MR. HERLING: Well, just to be clear: It is addressed for each new generator in the interconnection process. There is also a NERC transmission standard that requires us to test the entire system, which we do every year. So we test the stability of the entire system in the RTEP every year. We've never had a problem other than the two very small problems that I described earlier that were resolved by controlled devices within the plant and now artificial island. All of the other problems were always identified on a new generator as it was being requested to connect to the system.

MR. LeCOMTE: So you studied the problem on a regular basis. So we've identified a problem in one particular circumstance here. Tell me how would you address future problems or if you were to find the next problem?

MR. HERLING: Well, for the time being, we would address it in the same fashion. We would look for the most affective transmission solution, assuming that there were no easy control device solutions. Including a stabilizer on a plant is a fairly cheap solution, and we've done that before to resolve at least one problem in the past. So assuming there is no cheap control device solution, we would look for a transmission solution, we would look for the most cost-affective solution, we would ask the Board to approve it, and we would apply the cost allocation as it exists today, which iis based on solution-based defects.

MR. LeCOMTE: : Okay.

MR. ROLASHEVICH: Thanks, Ron.

So here's a question for PJM: Steve, in terms of your matrix, does this exhaust all possible categories in terms of --

MR. HERLING: Including the ones that I don't know yet exist?

MR. ROLASHEVICH: Yes.

MR. HERLING: : I believe it does. It's certainly possible that something can come up in the future, but I think it covers everything that is in our purview to implement through the RTEP.

MR. ROLASHEVICH: Again, I'm not asking you to predict the future, but do you think that any of these categories are subject to an increasing number of projects? Do you think that some of these projects are going to increase the number of projects listed in the PJM RTEP?

MR. HERLING: I think was the grid is aging you will see more aging infrastructure projects. I don't know whether we're going to see more storm-hardening projects; obviously, Hurricane Sandy was a pretty big deal. I don't know how much is left out there that we may find needs to be improved in that fashion.

Stability? I honestly don't think we're going to see very many of those as we move forward. I think this was a unique situation; I don't expect it to occur very often. We could have one more next year and then not again for 20 years; it's really hard to say.

Reactive problems, thermal problems, that's going to be 99 percent of the RTEP for a long time.

MR. ROLASHEVICH: I have one more question for the Maryland and Delaware State Commissions. So in terms of saying that an economic analysis, using something like an LMP analysis, is something we should look at. Are you saying that's in place of solution-based DFAX? And at the time are you saying there's some sort of hybrid that should be looked at?

MR. WEISHAAR: We would suggest that you look at that in lieu of solution-based DFAX unless there was some affirmative demonstration that this was a flow-based or thermal-based problem, and that hasn't been shown yet. So we have a disconnect between the driver or the outcome this project and the use of solution-based DFAX.

MR. ROLASHEVICH: Thank you.

MS. TEETER: Hi, this is Valerie Teeter with FERC staff.

. I just had a quick question, I'll start by addressing it to you, Steve, but anyone else can chime in if they're interested. So this is going back to your discussion a little bit earlier about the benefits projects to address short circuit issues, particularly transmission lines necessary. But just kind of more generally with respect to projects to address short circuit issues and then stability issues, what are really the benefits of these projects in the most general sense possible? And who are the beneficiaries? Is it a matter of the beneficiaries are just those whose direct problem is resolved? Whose problem is it really? Is it a given transmission owners? Is it an entire system problem? Can the problem change over time? I just want to get a better feel for how the system dynamics, and the fact that the system is constantly changing, impacts the benefits and beneficiaries of these projects.

MR. HERLING: I think you're talking about short circuit in particular?

MS. TEETER: Short circuit and projects

meant to address stability issues would be helpful as well. Thank you.

MR. HERLING: Okay. Well, the stability, clearly as long as the generation in a particular area continues to exist, that stability will continue to be a problem. If there were local load that could grow significantly, that would potentially -- you wouldn't need to deliver the energy further away on the transmission system. But it's really a function of how much generation you have in a local area and how strong the transmission system is to take that power away, okay. So, yeah, over time if a generator should be retired that could reduce the stability problems in a given area. But that's a fairly-easy-to-predict kind of a situation, it's not something that kind of creeps up on you.

Short circuit is harder in that respect because every generator added everywhere will contribute to the problem, maybe in very, very small amounts. Every transmission line you build will bump up the short circuit duty, again, maybe by very, very small amounts, but it's something we study every year. But as a breaker approaches its capability, we view it as not being a problem. When it reaches its capability then it's a problem. So if you want to look back over time we can see situation trending, but until you anticipate the need for the next big transmission line or the next generator building close by, you don't know when you might trigger that violation.

The nature of a short circuit problem is such that if a breaker is over-dutied and it's called upon to interrupt the fault, it may very well explode. Which, aside from the safety issues, will be disruptive to the ability of the grid to function in that area until such time as you can repair whatever damage has occurred. So it could have a noticeable impact on an area of the grid, and depending upon how severe the damage it could be a fairly significant problem.

MR. LeCOMTE: Thanks.

MR. RICHARDSON: Frank Richardson with the transmission owners.

I'd like to answer your question a little bit differently. Right now that stability problem that is solved at artificial island, there is a cost allocation for it. And I think we must remember that every zone in PJM is paying something for that project, every zone in PJM is benefitting from it. From solving the stability problem on artificial island, it affects the entire PJM grid. And everyone is getting a cost allocation. There is one zone who's getting a brand-new

230 kV line into their zone with 3,800 megawatts attached to it and they're getting a substantial amount of the cost for that project. On the surface and face value, that would make sense.

MR. LeCOMTE: Thanks.

Pass the mic down. Amy, please.

MS. FISHER: I appreciate that question. I think that's the obvious legal question that we all have to sit here and answer. Because what we're here to try to figure out is how these costs measure against benefits. And I just want to clarify in response to Chip's earlier comment, we are not relitigating Opinion 503. Opinion 503 said that merchant transmission facilities had to share in cost allocations for transmission upgrades. It did not say that we should not be measuring benefits relative to costs. So I just wanted to make it clear that we are not challenging Opinion 503, and I think that's important for everyone to understand.

However, what I would say is that there are benefits and there are incidental benefits. If the purpose of the upgrade is not to improve the way you use the system but you nonetheless benefit in some amorphous way, then that's why we have load share and the 50 percent of the project costs that are borne by load share. And I believe that's what Chip was just referring to. That doesn't mean that every person who incidentally moves power over the line should be cost allocated the same way that people for whom the blow-up of the transformer or the breaker is really what's being sought for.

MR. LeCOMTE: Thanks.

Mayer?

MR. SASSON: Thank you. A couple of ideas. I assume that when you said that everyone's paying for it and somebody's getting the line he's probably referring to the 50 percent socialization. Is that the case? When you said that every zone is paying, you mean because of the socialization?

MR. RICHARDSON: I don't have it in front of me. But everyone got an allocation, yes.

MR. LeCOMTE: Mayer, I'll give him a chance to answer. If you want to make your comment, and then if he has something to respond to, thanks.

MR. SASSON: I will assume that that's what he meant, that through the 50 percent socialization. And that is, depending on the voltage level, if the voltage level is lower it's a hundred percent DFAX so nobody else would be paying.

But what I wanted to answer your question very directly is: It's clear that the issue is short circuit, the issue of stability, the issue of storm hardening, we know what the issue is. And therefore solving that issue, depending on the purpose of the facility that you're putting in, you know what the purpose is, is to solve that issue. And the zones, where they are, that's who pays and that's what we've said, the zone pays. However, are there any flows on those lines? And I think that's what the confusion may be. Yes, there are some users for those lines but those users have incidental benefits because they're using it. But the line was not put for their benefit. But given any line there will be users, and those users have incidental benefits and they're not the primary benefits, which are those that had the benefit because of the purpose of the project of addressing the issue that brought the line. So you have -- you need to make sure we understand we have those two types.

MR. LeCOMTE: Thanks, Mayer.

If you could pass the mic down to Takis, please.

MR. LAIOS: Thank you. Takis Laios, PJM transmission owners.

Two observations: Obviously we're here trying to figure out why these cost allocations look as maybe blatant to some folks as compared to other cost allocations. But I want to throw two additional observations that we may want to take into considerations. As far as the merchant entities that were cost allocated, the projects in question here is that the cost allocation would be dramatically different to recognize that they're a single-load zone. If they were got a single-load zone, if that load was part of the host zone of the larger zone or the one that they're interconnected with, the cost allocations would be dramatically different. So the phenomenon that is a single load zone is a consideration.

Regarding the Del Marva cost allocations, we noted that's where the physics are putting the flows and solution-based DFAX measures those. So for this particular project it's not surprising by looking at the map as to where the project is goings; it's not surprising whose megawatts are flowing on that. But at the same token, there are lots of other projects throughout the rest of the PJM system the solution-based DFAX sees to it that the Del Marva Peninsula does not get cost allocated for those projects because, again, from a locational point of view the Del Marva load is far electrically away from those facilities. So basically, because you have one project here that may look maybe disproportionate in some eyes, you also have to take into consideration the other projects where the Del Marva loads are not picking up any cost allocation.

So on the whole, when you look at the entire set of the RTEP reliability projects, the cost allocational construct essentially is a portfolio or, if you will, a range of RTEP projects, essentially treats everyone the same. So it's not a situation where the construct is necessarily picking on this particular load to these particular entities. If you step back and look at the whole set of other projects and how solution-based DFAX treats them is equitable, again, on the large picture basis.

MR. LeCOMTE: Thanks.

One more question from staff and then we'll take a break.

MR. GROSS: Ed Gross from staff.

Question directed to Mr. Herling. It's kind of a thought experiment, actually, what I want to suggest, and an uncomfortable one at that. Assuming arguendo that a short circuit problem exists on the system which for some reason PJM missed, and a bad thing happened and we go well beyond what happens as far as for flows for the breakers themselves and we pass our 80 KA position, could you describe some of the effects that may have? Well, let me just ask you straight-up would probably be easiest. Short circuit problems that would happen would affect the system in general, the breaker, the connected facilities around that system, whereas possibly sounds like stability problems affect the generators and have more implications for the operations of the generators, would that be an accurate statement in your minds?

MR. HERLING: There's a bit of interaction there. If you have a stability problem, the generator that becomes unstable can swing and can cause other lines to trip. It can cause other generators to trip. It could spread into a more substantial problem or it could be very local and the generator trips and the system is just fine. So it really depends on the nature of the problem that initiates the stability event.

We've had some pretty significant system events that started out as stability problems. With short circuit, if you had a fault that exceeded the capability of a circuit breaker, either it's 80 KA or any size, it could be restricted literally to that substation. The breaker blows up a couple of lines open and that's the extent of the problem, or it could then cascade where you have lines overloading and more lines tripping, you could have local stability -- it could cause local stability problems on generators. And, again, depending upon circumstances if things go badly, it could cascade into a much more severe event. More than likely in both cases it's going to be very localized, but sometimes bad things happen. So it's possible that it could extend beyond the local area.

MR. GROSS: Just looking at the first-order effect, if you would, as far as either a short circuit event or a stability event, could you say that the short circuit affects more the system or stability affects more the generators, or you would say it's really depends upon the event?

MR. HERLING: Short circuit will have an immediate, physical impact on transmission infrastructure. Stability will have an immediate, physical impact on generating infrastructure. But the likelihood of that propagating out and affecting customers, meaning load, depends entirely on the circumstances.

MR. GROSS: Thank you for your answer.

MR. LeCOMTE: Okay, again, right on schedule. It's 2:45. Let's take a ten-minute break. We'll come back at 2:55 and have any followup. Thanks so much.

(Whereupon a short recess is taken.)MR. LeCOMTE: Okay, we had a few followup questions. Steve, I just wanted to see if you wanted to follow up on some of the earlier conversation?

MR. HERLING: I'm sorry, if I wanted to follow up.

MR. LeCOMTE: If you had a followup response, I think you indicated you had on some of the earlier questions related to the types of violations.

MR. HERLING: Yeah, you had asked me in particular of the one short circuit problem, and I had mentioned that there were a number of other projects that are already been identified which were then not required. That material is in one of our TEAC presentations, and that was a big part of why we chose that solution was because while it costs a lot of money, it obviated a number of projects on a net basis, made the project look much more affective. I'm looking at about nine projects that were identified for other reasons. I don't have all the particular violations. But they would have been built to resolve other problems and now they're not necessary.

MR. LeCOMTE: Okay, thanks.

MR. HERLING: We can get you the details and provide them at some later date if you wish.

MR. LeCOMTE: Just as a general thought,

though, that those violations would not necessarily have been short circuit violations?

MR. HERLING: They were not.

MR. LeCOMTE: Right, thanks. And violations that would have been allocated under the solution-based DFAX?

MR. HERLING: Yeah. My guess, without knowing for sure, is that that were all related to one thermal criteria violation or another, possibly a reactive violation, but they all would have been appropriately allocated using the solution-based DFAX.

MR. LeCOMTE: Thanks.

Mayer, did you have a --

MR. SASSON: Just briefly, Ron. Just to make sure it's clear: The entire BLC project is needed for a short circuit. And I think that's an important aspect. And I think Steve said earlier it's sort of an add-on that it can also solve the others, which is different. If you needed the project to solve one, another project to solve another, you choose one that's more efficient that solved both. That's not the entire one hundred percent of the project for short circuit. Now, it has other things, but...

MR. LeCOMTE: Thanks.

Val?

MS. TEETER: This is Valerie Teeter again with FERC staff.

Just one quick question for PJM for Steve. This is specifically about the chart that you provided in the appendix to your pre-technical conference comments. You indicated under the "end of life slash aging infrastructure criteria" that there is, in terms of stakeholder-identified issues, a question as to whether the flows over the original facility, that capability should be treated the same way for purposes of cost allocation as the incremental capability made available. Could you just elaborate on that point so we have a better understanding?

MR. HERLING: We were trying in that column to represent issues that various other parties have raised in a reasonably fair basis. That was a cost allocation question that had come up at one time; it was never really dealt with. But the obvious question is: If you simply replace something in kind -- which happens all the time, transmission owners maintain their own facilities and often have to replace circuit breakers or transformers of even parts of transmission lines -- if they replace them in kind, you may view that one way; if they replace it with something bigger and better and provides all kinds of additional capability, you may view it differently. And the question arose sometime ago: Should you kind of bifurcate and treat the original capability one way and the incremental capability a different way? But that's never actually been dealt with beyond having been raised.

MS. MARTIN: This is Valerie Martin for FERC.

I've heard comments here regarding benefits of flow travelling when you build a transmission, the new transmission facility, the benefit from travelling on the line. And I'm trying to understand what benefits do you derive from flow besides the line being built and over time while travelling on over it, what are the other benefits that you're defining over the years? Because you're talking about initially there are some beneficiaries that are easily identifiable, then you were talking about another project in 30 years it may be different.

MR. HERLING: Sure. I was describing two categories of benefit. One was just the pure use of the facility. All load needs to be served by energy; the energy has to get from generators to the load. So the transmission facilities that allow for that transfer of energy provide a benefit to that load. So if you build a new line and two zones make use of it to serve their customers, then they are clearly benefitting by its existence.

What I was suggesting was that the initial -- this goes back to when we used violation-based DFAX -- we then described the beneficiaries as the parties who caused the problem because the elimination of the problem returned the system to a reliable state. And those customers who previously had placed the system at risk are now benefitting by the system no longer be at risk. So the causers were the beneficiaries by the elimination of the problem. Now we use solution-based DFAX. Part of the rationale for solution-based DFAX was that for the vast majority of projects the users of the new facility are very similar to the causers of the initial problem. And if you think about flow from A to B, if you have -- people causing flow from A to B, if there's a violation, when you build a new line it's typically going to be in parallel with A to B and the people who caused the problem from A to B will now use the new facility, so the causers and the users after the fact are largely the same. So for 99 percent of the projects -- whatever the percentage is, I'm just throwing out a number -- we believe, PJM believes, that you're capturing both the causers and the users generally through solution-based DFAX. Where that doesn't quite work is when you have a short circuit problem or a stability problem -- because the users in the case of the solution to artificial island, you're solving the problem by building one more line, in this case from artificial island down to the Del Marva Peninsula -- you could have also built a line to Philadelphia or you could have built a line to Allentown or you could have built a line to Newark, New Jersey, and you would have solved the stability problem, and the users of that new line would have been noticeably different, okay. None of that use is the entire picture of who caused the problem.

Now, in fact, load isn't really causing the stability problem; it's a function of the relationship between the generators and the strength of the transmission system. But somebody, I think it was Mayer who pointed out, the reason you have the generators is to serve load, okay. So If you didn't have load, you wouldn't need the generators. So the fact that the generators are unstable means that we need to fix it so that we can use them to serve load.

MS. MARTIN: And over time that's how you're measuring the benefit?

MR. HERLING: Over time the use of the line tells you a lot about the benefits of that single solution. My point earlier was 30 years from now when one of the Salem units have retired, there will no longer be a stability problem, but the line will still be there and the line will still be serving a purpose and it will still be providing benefits. So the initial who-caused-the-problem beneficiaries will evolve over time.

My argument is with thermal overloads and reactive problems, it's largely the same so it doesn't matter. But with stability and short circuit, the original problem is not all that important after some period of time. I don't know whether that's one year, five years, 10 years. Over some period of time who caused the problem is no longer important. And that's why solution-based DFAX is a good indicator over a long period of time of who the beneficiaries are. So really the only question for me, for a really, really small slice of the RTEP pie, is who is the initial beneficiary related to the cause of the problem in addition to who's using the solution. To me that's only the really issue.

MS. MARTIN: So it's a cause and an addition to?

MR. HERLING: That's one addition. You got to decide whether that's a big enough issue to solve. We're talking about a couple of projects here. I realize it's a lot of money, but if we never have another stability problem ever again, okay, we can create a different solution, a different cost allocation solution, okay. I would like to keep it reasonably simple, we could come up with a different approach that blends in other types of beneficiaries. But honestly I wouldn't expect it to be used very often.

MS. MARTIN: Because you could come up with it yourself?

MR. HERLING: Oh, sure.

MS. MARTIN: Another question is in regards to once a project is selected to resolve the identified problems. And I've heard today that there's multiple -- there's a primary driver and there's other elements underneath that?

MR. HERLING: Yes.

MS. MARTIN: So for each of those, are there solutions for each one of those? Like a cost allocation solution for each on of those? How is that --

MR. HERLING: Actually, because we're using solution-based DFAX, this is one of the huge benefits of solution-based DFAX. Somebody's mentioned the Roseland project which had dozens, it might have been four dozen problems, that were resolved by Roseland. That's a 500 kV line and it was socialized. But to do cost allocation based on 48 or so individual violations and then weight them all and put them all back together then would have been a nightmare. With solution-based DFAX you don't need to do that; you have one solution that solves 50 problems; you have one cost allocation based on who uses the solution; not who caused each one of the 50 different problems. That's a huge advantage. That was one of the big reasons, that and the ability to redo the allocations every years based on changing system conditions. Those were the big advantages of moving to solution-based DFAX.

MR. SASSON: Can I comment on Valerie's question?

MR. LeCOMTE: Okay, since the mic's there. You're in jeopardy when it passes in front of you, Steve.

MR. SASSON: Valerie, you asked a number of important questions here. You asked a number of important questions here, and I want to make sure that it's clear that in my answer that we're not advocating for violation-based DFAX. That has to be absolutely clear, we said that from the very, very beginning. And I think Steve is saying for thermal overloads the solution-based DFAX is something that can be reproduced year by year over time. It makes sense because the users of the solution are the same as the causers, and there's consistency as we discussed. But we're here to answer the first question that the Commission asked: Is there a category of projects that are based on non-flow, not flow-based but non-flow? And I think we've answered that there are, there is a category of projects that have various -- depending on the nature of the problem, it could be storm hardening, it could be short circuit, it could be stability. So there a number of them. The question, then, is: Once you solve it with transmission, because there has been a violation, storm hardening, something got broken, there's a violation, now you solve it. The question being asked here to some extent is: Do you just cost allocate a little piece to whoever is the one that had the problem? And then later on you charge other people. And I'm not sure that's fair because the issue was the storm hardening.

Now, the fact that they're users later on, that's a different issue. But those issues are all incidental uses and we said there are two kinds, primary and the others. I think it's the primary you would need to address, and that's what I think we've given you an exact way of doing it.

MR. LeCOMTE: Thank you.

Takis?

MR. LAIOS: Takis Laios, PJM transmission owners.

One cautionary observation about the carving out of these special projects. That would necessitate drawing the line somewhere. Once you do that, you're inviting essentially another driver over project that falls outside the carveout that someone doesn't like the cost allocation that results from that project to argue that this should be included in that carveout. So the question right now is once you start a carveout, where do you stop? And that is a concern. And even within the carveout that we've been debating or discussing here today, I think Steve noted that there are differences between stability and short circuit, so even within the two classes of drivers that we're talking about here they're different from each other. So what stops a third, different driver from being argued that should be included in the carveout?

Today we don't have any carveouts. Essentially you're looking at the solution based-DFAX which measures where the physics are placing the flows. So that would be, again, just a cautionary observation as to if we embrace these two as being unique that that's going to open the door to a third driver is also unique and should be included with these other two. So I appreciate that.

MR. LeCOMTE: Thanks, Takis.

I'm actually going to get to you Amy. But as the mic passes by you, Steve, I want to follow up. You sat in the middle.

So I know I heard you make some comment about especially to the extent there was a carveout or some small class of reliability projects and that you maybe could identify a beneficiary's mechanism. Maybe you could elaborate on that. Where do you think you would go with identifying those beneficiaries?

MR. HERLING: : That's a trickier one. Stability, it's at least analytically, you can visualize the impact of a stability problem geographically. I can imagine a test. I'd have to talk to my engineers, but I can imagine a test that would show me where the impact dwindles to some de minimis level. Short circuit, I'm a little bit stumped. I'd have to think of how that would look like. I suppose you could look at the impact of generators, for example on a short circuit problem and the further away you get, that impact reduces to some de minimis level. But now you're associating the physical location of generators with the local load, which in a market environment there is no direct relationship between a generator and New Jersey and the load that lives right around it. So we'd have to think about what those implications might be; I don't have a good answer for you for short circuit.

MR. LeCOMTE: Thanks.

And Amy?

MS. FISHER: So I have to quote Maynard Keynes, which in our case is very appropriate because in the long run we are all dead. And I don't mean that for us as mortal beings, although it's true in that case as well. But I mean it in terms of the companies we represent sitting here. The fact that in some alternative universe we will be able to recognize the benefit of a 1.2 billion dollar project is really, very cold comfort for a company that's faced with costs that are simply in excess of its revenues. I think that if the ex-ante formula that we're trying to solve for is important to people, then it needs to work, not most of the time but all of the time. So we can make that happen in two different ways: We can either take the time and effort and not say "it's complicated" or "maybe we won't use it very much", to try to get that ex-ante formula as close to correct all the time as we possibly can; or when it doesn't work the people who are affected are going to come to FERC or the courts to get redress. And I think those are the questions we need to answer here. And failure to really dig hard into this formula means that's how it's going to be addressed in the future.

MR. LeCOMTE: Thanks.

Esam?.

MR. KHADIR: I would just like to make a cautionary regarding about anything on the solution-based DFAX. As I mentioned in my presentation and as we discussed here today, if we take a look at the short circuit issues you'll see that the short circuit is not the only driver; you have several drivers, including thermal drivers. If you take a look at the stability, stability is not the only driver. For artificial island there is a stability as one of the drivers. And the high voltages at artificial island was also another driver. And you're going to being in a lot of argument, a lot of disputes, and even a lot of issues in the future. Should we use the stability carveout or should be use the voltage in determining and keeping the DFAX? Same thing with the short circuit project, should we use the thermal drivers or should we use the short circuit drivers? Thank you.

MR. LeCOMTE:: Thanks.

I actually have a question for Takis as a followup. I'm going to stay away from the merits of other proceedings. But to the extent that the cautionary tale on carveouts and the transmission owner proposal to carve out from cost allocation certain proceedings, tell me the consistency there.

MR. LAIOS: There, at least in my mind, needing to take aback, obviously I'm representing the PJM transmission owners here. My response to that question would be basically all the other items we're talking about here, we're talking about requirements that apply to the entire PJM footprint. NERC reliability standards apply to the entire footprint; PJM planning procedures apply to the entire footprint. In that particular situation you're talking about something that applied to one zone. So therefore I view, at least in my case, differently from the carveouts that we're talking about here. Here you're talking about a short circuiting that can happen anywhere in PJM in order to address a requirement that PJM applies consistently throughout the PJM footprint. While in the other case you're talking about a particular local transmission entity choosing to -- because of unique needs that they may have in the local area, have essentially a driver that's unique to that zone. So it's not whether it's short circuit thermal or voltage, but what is the need that that particular entity's trying to address in their particular zone.

MR. LeCOMTE: As I said, I want to stay away from the merits for that.

If I can follow up with a question for Steve on that. So, if I were to look at the matrix, that end-of-life, aging infrastructure and the allocation methodologies indicated there is solution-based DFAX?

MR. HERLING: Yeah. And the reason for that is typically you're replacing a line with another line typically with more capability. But it's based -- once it's built, it looks just like any other new line. You can readily measure the use of the line. You could just as easily need to rebuild the line based on some thermal criteria violation. So once the solution is there, the use is readily measurable, and to me it kind of makes sense that you would continue to use it, the solution-based DFAX, as the appropriate measure of the beneficiaries.

MR. LeCOMTE: Thanks.

Mayer?

MR. SASSON: Today I find that I have agreed a lot with what Steve has said except this time. Now I disagree with him. The end-of-life violation that you mentioned of a particular line. Who caused that violation? That's the question we need to ask ourselves. Is it the load that was using the flows that were going to certain loads? Did they cause the end of life?

MR. LeCOMTE: Mayer, I want to make sure I understand, because to the extent we have the solution based and we identified beneficiaries, we've tried to stay away I think that the solution-based mechanism as clearly identified drives to the identification of beneficiaries, not problems identifying the universe of potential causes.

MR. SASSON: Ron, I fully agree with you that solution-based DFAX over a transmission line will identify the users; that is a given. However, that is not the real question I think we should be asking ourselves, which is: Why are we doing the project? And if you have an end of life, this line has been there for 40 years, is breaking apart, etcetera, we can't rely on it anymore, we got to replace it. Whether we are replacing the line or we are redoing it, we might as well do a better line so we have more capacity line for the future.

But was that the purpose of the line, to serve the load in a sense that those loads caused the problem? Other than they didn't, that goes to the question, I think also the answer I gave to Valerie, which in that case I did agree with Steve, which he said in stability in this case would put a line, we could have put it to Philadelphia or to Newark. So depending on the solution we charge different people, is that a fair approach? Who caused the problem? So it's almost like they're charging an innocent bystander because he was in Newark and he's there, he's the one I'm going to charge. "I had nothing to do with this issue." I think that's the thing I'd like us to think about a little, and that's why we came back in our opening remarks and said you look at the nature of the problem and for non-flow you look at what is the intended purpose of the project.

MR. LeCOMTE: I am always cautious when somebody asks that question if they can answer that.

MR. SASSON: It was by the thoughts that were given.

MR. LeCOMTE: Thanks.

Okay, I think I want to start by finishing by saying I appreciate all of the panelists, all of the comments, and in particular all of the people who have sat in the room and listened to quite a long dialogue about the Commission's questions here and the comments that we heard. I really do appreciate all of the participation today, and while I said I don't speak for the Commission, I think the Commission would support that comment. Thanks everybody.

I indicated that we're going to set up a schedule for post-conference comments and I'm going to backtrack on that just for a touch was I think we just want to regroup and see if we have any additional questions that we would want to include in those comments, and we would actually need some time to think about that. I will say that to the extent that we have comments, we have questions, I would like you to make sure you focus on the questions we ask. We've read all of the comments, we heard all of the comments today, and repetitive comments are repetitive. So with that detail, I'd like to say thanks to everybody and I think we'll conclude for today. Thanks so much.

(Whereupon the FERC technical conference scheduled for 10:00 a.m. on January 12th, 2016, is concluded at 3:30 p.m.)