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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

- - - - - -X

CONSOLIDATED EDISON COMPANY : EL15-18-001

OF NEW YORK, INC. :

-vs- :

PJM INTERCONNECTION, L.L.C. :

- - - - - -X

DELAWARE PUBLIC SERVICE : EL15-95-000

COMMISSION and MARYLAND PUBLIC :

SERVICE COMMISSION :

-vs- :

PJM INTERCONNECTION, L.L.C. :

- - - - - -X

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

-vs- :

PJM INTERCONNECTION L.L.C. :

- - - - - X

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

- - - - - -X

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

- - - - - -X

1 Room 3M
2 Federal Energy Regulatory Commission
3 888 First Street, Northeast
4 Washington, D.C. 20426
5 Tuesday, January 12, 2016

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

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1 FERC STAFF:

2 JASON FEUERSTEIN

3 SHAWN SNOW

4 KEATLEY ADAMS

5 RANDY JOHANNING

6 EDWARD GROSS

7 PETER ROLASHEVICT

8 RON LeCOMTE

9 VALERIE MARTIN

10 VAL TEETER

11 BEN FOSTER

12 KEVIN JONES

13 DOUG MATYAS

14 PRESENTERS:

15 STEVE HERLING and PAUL McGLYNN, PJM

16 FRANK RICHARDSON and TAKIS LAIOS, PJM

17 Transmission Owners

18 MAYER SASSON, Con Edison

19 AMY FISHER, Linden VFT

20 ROBERT WEISHAAR and JOHN FARBER,

21 Delaware/Maryland Commissions/Agencies

22 ESAM KHADIR, PSEG

23 JEFF WOOD, Hudson and Neptune Transmission

24 MARK RINGHAUSEN, ODEC

25 Court Reporter: Alexandria Kaan, Ace-Federal Reporters

P R O C E E D I N G S

1 P R O C E E D I N G S

2 (10:00 a.m.)

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

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

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

23 Please note that this technical conference
24 is being transcribed in order to provide an accurate
25 record. For the benefit of those monitoring the

1 conference by telephone or in person, please always
2 state your name and if you've not already done so, who
3 you will be representing and speaking. Please place
4 your table tag at its edge if you wish to speak, and
5 wait for the microphone. Because they may interfere
6 with room communication equipment, please silence your
7 phones.

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

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

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

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

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

20 MR. ROLASHEVICT: Good morning and welcome,
21 Pete Rolashevict, economist.

22 MR. LeCOMTE: Ron LeComte, OGC.

23 MS. MARTIN: Valerie Martin, Office of
24 Regulations.

25 MR. FOSTER: Ben Foster from the Policy

1 Office.

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

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

6 MR. JONES: Kevin Jones, OEMR East.

7 MR. HOLDENBERG: OGC.

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

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

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

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

18 MS. FISHER: Amy Fisher, Linden VFT.

19 MR. SASSON: Mayer Sasson, Con Edison.

20 MR. HERLING: Steve Herling with PJM.

21 MR. RINGHAUSEN: Mark Ringhausen with
22 Electric Cooperative.

23 MR. KHADIR: Esam Khadir with the PSEG.

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

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

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

18 You are to efficiently address the
19 Commission's directives. I will cut off questions that
20 go beyond the scope of the Commission's directs. A
21 schedule for post-technical conference comments will be
22 announced in the afternoon session. I just wanted to
23 make one statement for those on call: To the extent you
24 have questions, I understand in the notice that the PJM
25 defects CONF designated list had not been accessible

1 from outside. That should be corrected. If you get a
2 bounceback on that, please send an e-mail to
3 ron.lecomte@FERC.gov. Thanks so much.

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

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

25 We also identified a couple of lesser

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

14 Now, there have been a great many short
15 circuit problems that have been resolved in the RTEP,
16 but in all cases but one they have been resolved by
17 upgrades to the circuit breakers at a particular
18 substation, or they have been part of the solution to a
19 thermal problem where you build a line and the line over
20 duties the circuit breaker and as a result the
21 replacement of the circuit breaker is associated with
22 the line project. So there's only ever been one short
23 circuit problem that had to be resolved by something
24 other than the replacement of the circuit breaker. In
25 the short circuit issue and the stability issue, again,

1 the benefit of solution-based defects over time does
2 represent the flows that are made on the facility that
3 is solving the problem, okay. The initial nature of the
4 problem may not necessarily be related or entirely
5 related on those flows, but over time the evolving use
6 of the facility is well-represented by the
7 solution-based defects. One of the challenges -- and as
8 we talk through this today and in the future with
9 identifying the cause of a problem -- if you look at the
10 short circuit issue, for example, there is no one single
11 cause that you can point to to that particular short
12 circuit problem. It's something that kind of evolved
13 over time as a great number of solutions were put in
14 place that had very small impacts on the fault duties at
15 the substations in question. And in a given year we may
16 have 100 projects that are introduced into the RTEP.
17 Each one has a very small impact. We may add
18 generators; there may be generators added in New York
19 that have a small impact on the fault duties. So as we
20 move forward we'll find that it's going to be very
21 difficult to point to a single causal element that you
22 could say on day one is the reason why we had to change
23 out -- in this case not change out a circuit breaker but
24 build a line to redirect fault currents. So over time
25 the solution-based defects works pretty well.

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

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

11 MR. LeCOMTE: Thanks, Steve.

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

16 PJM Transmission Owners.

17 MR. RICHARDSON: Good morning. Takis and I
18 are representing 16 companies that are PJM Transmission
19 Owners in PJM. The 16 Transmission Owners have a
20 collective responsibility for the design of their
21 current PJM RTEP cost allocation methodology. We have
22 considered the comments submitted by the parties in the
23 technical conference and we continue to support the
24 current cost allocation methodology as the best
25 available. We hope our comments this morning and the

1 discussions today will provide more informed context for
2 the Commission to make decisions within. We view the
3 comments submitted as representative of kind of a
4 microcosm of what happens when cost allocation is not
5 performed using an objective, repeatable measurement of
6 benefits based on accepted engineering principles. When
7 cost allocation is left to concerns, perceptions, and
8 opinions, we have what we have before us, a comment
9 today. Where no entity is put forth, as the Commission
10 requested an alternative, neutral, and objective ex-ante
11 cost allocation method or rational delineation of the
12 subset of reliability projects to apply it to. Instead
13 we have commenters on topics of both sides, Delaware and
14 New Jersey in the case of the artificial island project
15 cost allocation. We have parties who want to revert to
16 causation principals in allocating for claiming, "I
17 didn't cause the problem. I don't benefit from the
18 solution" in order to put costs on others. We have
19 parties who want to discard the methodologies we have
20 for actually measuring the benefits of reliability
21 projects and exchange it with the measure of economic
22 benefits to put the cost on others. We have parties who
23 want to modify solution-based defects, calculations, to
24 put costs on others. We have parties proposing special
25 cost allocation rules to be applied just for merchant

1 transmission facilities to put costs on others. We have
2 parties proposing a definition of benefits unique to
3 merchant transmission facilities to put costs on others.
4 And lastly we have parties who arbitrarily declare that
5 the solution to this problem is to put all charges to
6 the local zone, charge all zones, charge generators, and
7 do that, and in addition we'll take a rule allocation
8 along with that as well. And all of these propositions
9 are focused on singular projects of concern to the
10 commenters, and all of the propositions are designed to
11 their benefit. This is representative of what happens
12 when projects are looked at in isolation or we revert to
13 causation as the basis for cost allocation.

14 What we do not have in the comments is an
15 alternative methodology ex-ante, it's repeatable, it's
16 an objective measure of benefits that works across
17 geography, across time, and across all types of
18 reliability projects. We do have that in a
19 solution-based defects methodology; it's the best method
20 available. It's based on industry-accepted engineering
21 principals, not perception, appearance, or the party's
22 unsupported opinion of "this is who I think should pay
23 for this." The Transmission Owners offer that specific
24 cost allocations should not be evaluated in isolation of
25 all the other integrated components of the PJM schedule

1 cost allocation methodology in considerations outside of
2 just the defects methodology that result in some parties
3 being exempt from certain costs and other parties paying
4 certain costs. The cost allocation process and
5 methodology has to be taken as a whole, looked at as a
6 whole, and should not be attacked piece by piece in
7 isolation of each other, project by project, and
8 singling out the defects component of the entire cost
9 allocation methodology. We believe attempts to
10 categorize reliability projects differently will be
11 fraught with problems and will lead to more litigation.

12 For a large percentage of reliability
13 projects there are multiple violations and reasons
14 causing the need for the project, as well as future
15 violations that will be mitigated. Time to agree upon
16 and split out the causes of allocations will be
17 subjective, circular in reasoning, riddled with
18 conjecture, and will be argued project by project
19 because each of the projects are unique. Because of
20 this, the Transmission Owners changed the game with our
21 last cost allocation of filing and focused on
22 objectively measuring the use of the facilities to
23 measure for cost allocation, and to put that controversy
24 to an end by going to measuring the use. As the New
25 Jersey parties wisely point out, ultimately every

1 project is for waste, regardless of the cost or the need
2 for the project. The Transmission Owners believe that
3 cost allocation can be perceived as unfair but project
4 by project alterations to the PJM cost allocation
5 methodology is not proper. Change to the cost
6 allocation methodology should be evaluated over long
7 periods of time with a mounting body of evidence over a
8 larger amount of projects and as an integrated whole,
9 and not in the context of a single project cost
10 allocation where there will be winners, there will be
11 losers, and there will be losers who will litigate, and
12 that won't jeopardize the progress that we have
13 complexed so far with the cost allocation methodologies
14 and PJM.

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

24 MR. LeCOMTE: Thanks.

25 Presentation on ConEd, please.

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

15 Any flow-based benefits that may result from
16 these and other non-overload projects are incidental to
17 their intended benefit and their stated purpose. Some
18 parties have argued that it is difficult for PJM to
19 identify which category a project belongs in; that is
20 incorrect. PJM already makes distinctions today. For
21 example, when PJM filed a cost allocation for the VLC
22 project with the Commission it identified their relief
23 problem as over-dutied breakers, and the fail criteria
24 short circuit. And the final cost allocation for this
25 failed to identify the problem as damage due it Sandy,

1 and the failed criteria as a piece of criteria. PJM
2 also brought in a matrix in advance of this technical
3 conference, as Steve just mentioned, the device projects
4 according to their purpose. Clearly, this is something
5 PJM does and can do.

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

19 A practical matter: This means allocating
20 the costs of non-overload projects to the transmission
21 zone or zones that benefit by receiving relief from the
22 non-overload issue. Some parties have claimed that this
23 would be a violations based approach; we've gotten that
24 complaint. But that conversation is incorrect and
25 serves only to obscure matters by hardening the facts to

1 disputes. Let me be clear: Con Edison is not
2 advocating a violation-based defects analysis period.
3 Our position is that for non-overload projects no
4 defect, violations, solutions, no defects analysis can
5 apply because there is no rational or technical
6 relationship in the flows and intended beneficiaries.
7 The only justifiable way to identify prospective
8 beneficiaries for non-overload projects is to identify
9 who it's intended to benefit, given the project's
10 purpose.

11 I will now discuss a little bit more depth
12 -- and I do note that it is summarized in a couple
13 slides that we have that are out there, you can take a
14 look at. With respect to the first question, defects
15 analysis is the wrong cost allocation method for
16 non-overload projects because it relies on distribution
17 factors which lead to flow-based measures. Distribution
18 factors are the basis to quantify the amount of flow
19 that each individual load contributes to the total flow
20 over a specific line. Distribution factors are
21 multiplied then by load to get flow, which are then used
22 for cost allocation. For example, a load has a
23 distributing factor of two percent relative to a given
24 transmission line means that two percent of that load
25 flows to that line. But for non-overload projects,

1 there is no rational relationship between the flows and
2 the intended benefits. This makes the use of
3 distribution factors as part of a defects analysis a
4 portion of it.

5 For example, the purpose of the VLC project
6 is to address short circuit violations. Short circuit
7 has nothing to do with energy flows. Energy flows are
8 the result of customer demand. Short circuits are part
9 of the system that are disturbances of the result of
10 generator current of an overwhelmed circuit breaker.
11 Because short circuits have nothing to do with energy
12 flows, the intended benefits of fixing a short circuit
13 cannot be measured by flow. The same is true for the
14 Warren project. The Warren project is intended to
15 rebuild the system damaged by Storm Sandy. If it can be
16 recovered, it's not a benefit that can be measured.

17 Finally, the artificial island project is
18 intended to enhance stability, not enhance growth. For
19 these and future non-overload projects the defects
20 analysis is the wrong tool to use and using it will
21 necessarily result in cost allocations that are unjust,
22 unreasonable, unduly discriminatory, and not wrought
23 with the message of benefits. With respect to the
24 second question, it is important to make one threshold
25 point: Some parties in these proceedings have argued

1 that Con Edison and others had no right to challenge
2 their cost allocations for any individual project so
3 long as the defects analysis worked for most projects.
4 We categorically reject that position. It gives each
5 party a right to adjust the reasonable cost allocation
6 for each and every project, as well as the unqualified
7 right to challenge any cost allocation that it believes
8 fails this step. To ensure that costs are just and
9 reasonable and at least roughly commensurate with
10 benefits, the cost allocation method for none of our
11 projects must identify intended beneficiaries. If
12 intended beneficiaries cannot be identified by flow,
13 they must be identified by reference to the intended
14 purpose of the project. For short circuit projects like
15 the VLC projects, intended beneficiary is the
16 transmission zone where the short circuit exists. Why?
17 This is because excessive current, if not removed, will
18 result in the physical damage and the physical failure
19 of equipment in that degree. This conclusion is
20 supported by two additional points: First, short
21 circuits are usually resolved through the
22 interconnection process and paid for by the
23 interconnecting party. Second, as PJM has stated, the
24 typical solution for a short circuit problem is to
25 repair roughly the break, not to build a transmission

1 line. This underscores the rationale to measure
2 benefits of short circuits.

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

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

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

3 MR. LeCOMTE: Thank you, Mayer.

4 Amy?

5 MS. FISHER: Amy Fisher with Linden VFT. In
6 light of what we believe are glaring shortcomings in the
7 PJM open access transmission power Schedule 12 cost
8 allocation process, Linden VFT is pleased with the
9 consent Commission understands the 2013 RT cost
10 allocations, which we have protested, may not be just
11 and reasonable. We're in general agreement with Con
12 Edison that it benefits the project which do not address
13 a need for increased power flow, should not be measured
14 by proxies based on relative power flow. Several of the
15 2013 RTEP projects addressed local short circuits
16 violations in the central portion of the utility load
17 zone by rerouting the current among additional
18 substations. Whether those substations also
19 interconnect at or near Linden VFT will determine
20 whether Linden VFT is allocated costs to resolve this
21 short circuit problem. Had the local utility decided to
22 spread the current within its own load zone, Linden VFT
23 would be allocated fewer or no costs.

24 Regardless of which individual substations
25 are allocated, the short circuit problem will be

1 resolved. However, the cost allocation will
2 dramatically stay. If the utilities plan, counsel
3 working at the local VFT local connection point a
4 significant cost allocation could be shifted for Linden
5 VFT even though Linden VFT received no benefits to
6 offset those costs.

7 Another 2013 RTEP project is repaired
8 existing substation following damages caused by
9 hurricane Sandy, the Warren project which Mayer referred
10 to. It, too, was planned to permit the local load
11 serving entity to fulfill its ratepayer obligations, and
12 the criteria project was not needed to address
13 reliability, market efficiency, or public policy
14 requirements. Our addition to Schedule 12 as has been
15 proposed would be helpful if it clarified the different
16 types of transmission expansion projects, may require
17 different proxies to determine project benefits. By the
18 way Linden VFT reads Schedule 12 to require differential
19 readiness, but PJN disagrees. However, if so modified,
20 Schedule 12 would not be a valid ex-ante project to cost
21 allocations, at least to the extent applied to us.
22 Ex-ante cost allocations formulas can simplify cost
23 allocation determination as to expense, but they only
24 justify to the extent that they produce results which
25 are fair. Under relative law that means cost

1 allocations which are roughly commensurate with benefits
2 received. Applications and ex-ante formula in a way
3 that violates that standard means the ex-ante formula is
4 wrong, even if the formula may often work as intended.
5 A potentially responsible payers' concern is an
6 indication that the ex-ante formula may not be producing
7 results that are roughly commensurate with benefits. It
8 should be taken seriously, not trivialized.

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

21 The Commission was told at that time that
22 the resulting ex-ante formula, which is referred to as
23 you know as the solution-based defects, employs use of a
24 transmission upgrade as a proxy for the benefits of that
25 upgrade, and that this rule would always, always produce

1 cost allocations which were roughly commensurate with
2 benefits. In fact, under Schedule 12 in order to
3 produce a roughly commensurate result the solution-based
4 defect result only becomes cost allocations after
5 application of savings rules. The one percent de
6 minimis netting rule in the related gross of provision,
7 which we've talked about. These effectively allow the
8 LSE's to limit their contributions to projects outside
9 their own load zone, thus the ex-ante formula is not due
10 to equal benefits as you have heard. But use of the
11 proxy for benefit except when that would not make sense
12 for LSE. Such a formulation might pass if it were not
13 for the fact that the savings rule significantly
14 discriminate against Linden VFT and similar parties, and
15 therefore provides none of the consensus-driven planning
16 and coordination value which the Commission associates
17 with ex-ante rules. What this ex-ante formula is able
18 to do is permit the load-serving utilities to calculate
19 in advance the ability they will have to offload the
20 cost of their upgrades on to other parties and to design
21 those upgrades to take advantage of the arrangement.

22 To be clear, the most well intentioned LSE
23 has incentives in the application of Schedule 12. It an
24 LSE expects to flag transmission concerns, plan the
25 solution, and add the resulting project to its rate

1 base. It can also eliminate ratepayer concerns if the
2 projects are assigned to other system users. The claim
3 by the PJM LSE's that the projects Schedule 12 cost
4 allocation methodology worked well is over stated. As
5 we have indicated, it is not 95 percent of the
6 allocations that worked just fine, but rather when you
7 calculate only those projects that were used, that
8 solution-based defects was used to cost allocate, you
9 end up with 74 projects, seven of which were completely
10 allocated to the local load zone and therefore not
11 contentious, and 60 of those 74, 81 percent, are the
12 subject of protest.

13 In addition, litigation sought by the
14 western LSE's in 2005 resulted in a major revision to
15 the previous ex-ante methodology which presumably
16 everyone thought was fine at the time, as recently as
17 2012 and in that case has still not been fully resolved.

18 PJM's prevailing view is that there are no
19 bad projects, only bad cost allocations. And it takes
20 no responsibility for cost allocations, it merely
21 applies the formula given to it by the LSE's. However,
22 divorcing project selections from cost allocation is bad
23 policy because separating the question of what to build
24 from the question of who benefits from upgrades also
25 eliminates important checks and balances in assessing

1 the timing of the specific projects. Under the PJM TO,
2 cost allocation information with respect to a proposed
3 project does not relieve until the project has been sent
4 to the PJM board for approval. Failure to consider cost
5 allocation in project allocation means that more
6 efficient in cost effective have no objective meaning.
7 It is nonsensical to state that a larger regional
8 project is less costly than a series of smaller local
9 projects without considering the question of less costly
10 for whom. An RTEP example of how this working practice
11 is the Bergen-Linden corridor project which includes the
12 new substation for Newark Airport, important locally but
13 without benefit to Linden VFT. Had it been clear at the
14 time of project design and selection that Linden VFT and
15 not the New Jersey ratepayers would be bearing that
16 project cost, questions about benefits received would
17 have been obvious. Instead under the current oath there
18 is literally no one who considers the cost benefits to
19 Linden VFT of that decision.

20 We can see from the comments of the
21 artificial island cost allocation component that they
22 have made the suggestion that all projects be evaluated
23 under economic criteria to try to put some limit on the
24 planning process. Linden VFT contends that the PJM RTEP
25 rule require consideration of the issues already. The

1 regional transmission expansion planning protocol is
2 required to avoid the imposition of unreasonable costs
3 on any transmission owner or any user of transmission
4 facilities. Section of the oath requires that any cost
5 assigned to an MTF be reasonable. Instead the cost
6 allocation results for the New Jersey project is that
7 890 million out of the total of 1.1 billion are the
8 responsibility of parties other than the LSE in
9 undeniably not just and reasonable. The likely result
10 of this cost allocation will be that the parties who
11 receive the allocations will be forced to relinquish
12 their rights. Since the New Jersey projects upgrades
13 are according to PJM still necessarily, as Mayer pointed
14 out, they will be paid for by the load zone in which
15 they are located after all. But the resources 1,600
16 plus megawatts will be lost. This is the local minority
17 disparagingly referred to by the New Jersey Board of
18 Public Utility.

19 We remind the Commission that MTF are
20 different and MTF is not an electric load, it's a
21 transmission line. In Linden VFT's case it's a type of
22 transformer. In PJM an LEC's determination to add a
23 transformer will be studied to determine its effect on
24 the system and costs to address resulting changes will
25 be included as but-for costs. MTF also pay their but

1 for costs through a generator-like interconnection
2 process. No one suggests that a utility transformer,
3 once incorporated into the grid, should attract ongoing
4 upgrade investments. Also, MTF is not a traditional
5 load zone, which is user and energy producers. It is
6 simply a device which power delivered over PJM lines of
7 the somewhere else, and in the case of Linden VFT loads
8 them back somewhere else. The price of power region
9 determines where that power goes. Although PJM must be
10 aware of the plan of system and FTS does not use power
11 in the way that rate payer load does. There appears to
12 be a belief among some parties to this dockets that
13 MTF's are not paying their fair share of system costs
14 when there is a withdrawal of power from Northern New
15 Jersey, and this view is wrong. With respect to energy
16 transfers, PJM and NYISO conduct their own procedures
17 under coordinated transaction scheduling. A generator
18 can choose which market to participate in.

19 Linden VFT energy flows are no different.
20 If a Linden VFT customer determines to participate in
21 the Newark capacity market, it delists in PJM and
22 doesn't receive capacity payments from PJM. Market
23 forces determine where generation is best allocated and
24 drive price convergence between regions exactly as
25 desired under this Commission's interregional planning

1 principle. The fact that an MTF may facilitate these
2 options for generation does not just guide the
3 imposition for cost allocations, which benefit does. So
4 what is to be done? First and foremost, all parties
5 need to recall that cost allocations must always be
6 commensurate with the benefit a party receives and no
7 parties are entitled to be free riders. Projects which
8 have their underlying purpose of allowing a service in
9 the zone given the age of existing infrastructure,
10 damage to existing equipment, short circuit currents,
11 and similar upgrades, are more fairly allocated to the
12 load zone which would allow those projects to be
13 assessed by state regulators to determine cost
14 containment.

15 The LSE's would like to maintain the
16 existing 12 formulation, at least for the bulk of power
17 flow process where it results to sponsoring loads,
18 sparing the bulk of project cost. Subjects to review
19 and analysis, Linden VFT main have no objection to those
20 as long as the LSE's are willing to revise the
21 formulations so as to provide savings benefits to MTF so
22 that incidental benefits are not the basis of cost
23 allocation for them. This means an equivalent de
24 minimis figure which would serve to reduce the
25 facilities for which Linden VFT is responsible and

1 netting concepts that give it back to MTF peak-load
2 operation, and reasonable determination of the likely
3 sources of the MTF generation, each of which is
4 comparable to existing rules for LSE's. It also means
5 rethinking the growth provisions of Schedule 12 which
6 exclusively reallocate costs from beneficiaries to
7 non-beneficiaries. Acknowledgement in Schedule 12 to be
8 made at MTF are not traditional load zones but are
9 transmission facilities.

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

1 if RTEP costs are imposed upon them.

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

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

15 MR. LeCOMTE: Thank you, Amy.

16 Bob or John?

17 MR. WEISHAAR: Thank you and good morning.

18 I'm Bob Weishaar, speaking on behalf of the Delaware
19 Public Service Commission, the Maryland Public Service
20 Commission, Delaware Division of Public Advocate, and
21 the Maryland Office of People's Counsel.

22 Artificial island is an area on the eastside
23 of the Delaware river that is seldom more than 3,000
24 megawatts of nuclear capacity. We're close to three
25 decades that nuclear capacity has been operating subject

1 to what's known as that artificial island's operating
2 guide. In spring 2013 PJM determined that an RTEP
3 project should be developed to address these stability
4 issues that are currently being addressed via the
5 operating guide. And after an extensive RTEP process
6 involving many competing proposals over a rather lengthy
7 period of time, PJM ultimately settled on a combination
8 of projects to be developed by LS power, PSEG, and PHI.
9 The total estimated cost of the project is more than a
10 quarter billion dollars. Of this total cost
11 approximately 246 million or 89 percent of the total is
12 proposed to be allocated just to the Del Marva zone. Of
13 the SBD facts portion of the project, 99 percent of that
14 total is proposed to be allocated just to the Del Marva
15 zone. At the Delaware Public Service Commission's
16 request, PJM conducted an economic benefits analysis,
17 essentially the same market efficiency analysis that PJM
18 conducts under Schedule 12, section B5. That analysis
19 revealed that only 10 percent of a total benefits of the
20 project would go to the Del Marva zone. This mismatch
21 between an allocation of 90 percent of total project
22 costs and 10 percent of project benefits are why John
23 and I are here today. The state agency has exhausted
24 all options in the PJM stakeholder process. They
25 participated extensively in the TO act: They wrote

1 letters to the PJM Board; they presented proposals to
2 the TOAAC; they had extensive discussions with PJM and
3 individual Transmission Owners. All of which led up to
4 what we have here today in terms of the record.

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

21 And of all the parties to the proceeding,
22 only the PJM TO's and just recently the New Jersey's
23 state agencies suggest that we just ignore the gross
24 mismatch between costs and benefits, that somehow
25 artificial island is a sufficiently flow-based project

1 to fit within the current SBD facts paradigm or that
2 somehow SBD facts will produce rough justice. Neither
3 of the parties states exactly how that will occur in the
4 end.

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

1 appropriate questioning; and in that regard, PJM's
2 preconference comments were helpful.

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

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

14 MR. LeCOMTE: Thanks, Bob.

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

18 MR. KHADIR: Thank you and good morning
19 everyone. My name is Esam Khadir, I'm from PSEG. Go to
20 slide 2, please. For the sixth time I'm going to let
21 you read line 2, talking about who PGMG is at your
22 leisure. As the first question, PGMG believes
23 solution-based defects is just and reasonable and is a
24 superior, non-discriminatory, ex-ante cost allocation
25 methodology. Power flow driven versus non-power flow

1 driven is not an appropriate distinction. Underlined
2 caution does not warrant any distinctions.

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

23 Non-power flow violations cannot be
24 pigeon-hold as localized concerns. If you take a look
25 at voltage, which is on the power flow issue, you see

1 that the project, which was a regional measure, is a
2 voltage violation project. Voltage issues affecting
3 east and central cases, those are 500 KB interfaces and
4 also regional. So voltage could be regional. Those are
5 the issues.

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

13 Slide 6, please. Carving out categories
14 from the solution-based defects will read the future
15 reviews. If we take a look at the question that we're
16 here for today, artificial island. The baseline for
17 operational performance project, this is both system
18 stability and high-voltage reliability issue. I can
19 argue very well that the problem in artificial island is
20 a stability problem, not a high-voltage problem. They
21 can argue that is a high-voltage problem not a stability
22 problem. The VLC project, the baseline reliability
23 project that has risen a variety of reliability issues
24 including several and short circuit projects, as well as
25 the short circuit issues. The project, this is the

1 project that has aging infrastructure as well as short
2 circuit issues. Again, we can argue which one is which.
3 The next project, it's a baseline that's a driven solely
4 by violation short circuit. How would be address that
5 one? Which category are we going to pigeon-hole it to?

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

9 Slide 8, please. Solution-based defects is
10 a superior cost allocation approach. PJM has had this
11 defects. Problems with violations based approach
12 include: Unmanageable from project of written a high
13 number of violations; a local project we had 53
14 violations to start with, unmanageable to come up with
15 the cost allocation violation defect. Overly cumbersome
16 approach. Results may not necessarily be repeatable on
17 an annual basis because violations could differ. The
18 violations that you have today, a generator could come
19 in tomorrow and completely erase that violation, or
20 another generator could retire and that violation would
21 go away. To adequately capture future violations of a
22 future project and are not suited for a voltage or other
23 issues such as short circuit or stability because those
24 violations would require use of power flow baseline and
25 we have to get proxies or surrogates in order to be able

1 to analyze. The proxies would require exercises of
2 engineering judgment and making an exact time. What it
3 basically says is that if we're carving out short
4 circuit and stability PJM, better allocation with
5 violations of allocation, the violation based defects is
6 not going to help because it's not a good or accurate
7 measure.

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

15 Slide number 10, please. PSEG has already
16 addressed an appropriate allocation with methodology for
17 VLC and a northern engineering and an underlying docket.
18 We are not covering the same ground now, but we do offer
19 this deeper regarding the cost allocation for the
20 artificial island project. I'm going to go a little bit
21 more into the benefits for the artificial island project
22 as it pertained to the Del Marva area where it is the
23 primary beneficiary of the artificial island project. If
24 we take a look at the map that we have in front of us,
25 the yellow highlighted system that is the Del Marva

1 area. And a couple things that you can notice there:
2 The only times that the outside of Del Marva has are
3 basically in the North and the orange or red lines are
4 500 KB, the greenish blue lines are 2 KB. So if you
5 take a look, there are a million interconnections,
6 primary million connections of the 500 KB at two points,
7 one is the red line and one is blue.

8 Just a to give you a little bit of
9 information on the Del Marva system: It's load is over
10 5,000 megawatts; it's served by two 500 KB transmission
11 lines into two 500 KB stations; and it also has some
12 load capacity due to KB lines in the North and one 138
13 KB transmission line. The Del Marva area has been
14 subject to transmission constraints and congestion in
15 the past, and still does. The Del Marva area has very
16 old generation, over 30 percent of this generation is
17 over 30 years old, high capacity -- sorry, with a high
18 risk of retirement into the load and environmental
19 regulations that we have today. The amount of
20 generation that we have in Del Marva is less than the
21 amount of load that Del Marva has.

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

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

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

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

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

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

13 MR. KHADIR: Okay. I wanted to talk a
14 little bit about the market efficiency analysis that the
15 Delaware Commission had mentioned, but I'm not going to
16 have time to do that. I hope that you give me a chance
17 later on to talk about it. The other thing, too, the
18 Del Marva Peninsula has separated from PJM and RPM twice
19 before, once in 2010-2011 and the other one in
20 2012-2013. That means that there is potential for it to
21 split again, which is a huge cost to the Del Marva zone;
22 it happened. Having a line that is run from artificial
23 island into Del Marva, it greatly increases the value of
24 the capacity energy atmosphere limit of the zone, which
25 subsets and avoids the increased capacity crisis.

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

5 MR. LeCOMTE: Thanks, Esam.

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

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

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

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

10 Turning the page, I just wanted to give
11 everyone a sense of what Hudson is. The foreground of
12 this photograph is the Hudson converter station, and in
13 the background is the PSEG substation. We connect to
14 the PSEG substation shown by the whole line there at the
15 230 KV level. We convert that AC from DC in the white
16 building, then it converts back from DC to AC and we
17 transport it across to New York at 335 KV. It's
18 important to note that we are interconnecting at the 35
19 KV level, and that has to do with a similar upgrade that
20 we're responsible for building which is a Bergen line to
21 230 KV upgrade that was allocated to us.

22 To go to the next page. What are merchant
23 transmission facilities? What are we not? We do not
24 have any inactive customers, we do not recover our
25 customer base. The only way we recover our cost is from

1 the sale of capacity and energy across the line. So
2 effectively the only benefits that we can ever garner to
3 give us a bill to recoup cost is something that's going
4 to reduce the cost of capacity and energy to PJM or
5 increase the price of capacity of New York ISO, or allow
6 us to sell more energy capacity across the line at the
7 same spread, recognizing that if we seek to increase our
8 SBWR we have to make another interconnection request,
9 and if there are any associated upgrades with that we're
10 responsible for these costs.

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

23 Let's skip two pages and go to the cost
24 allocation. I don't think this is in disagreement
25 anywhere, but there were comments made earlier is cost

1 causation the right method for cost allocation? So if
2 we turn to the pages titled cost allocations, I wanted
3 to talk briefly about the specifics of Hudson
4 Transmission. In that particular case we've been
5 allocating slightly more than 300 million dollars in
6 upgrade costs for work that was performed in PJM that
7 came out of our interconnection studies to allow us to
8 resolve 320 megawatts of FTWR's. The biggest component
9 of that was the 380 KB Bergen transmission line, which
10 just went operational November 30th. We've been using
11 it for less than two months. Now, the tariff required
12 that we pay a hundred percent of the costs on that
13 because it was very easy to determine who caused the
14 problem. That's the tariff; we agreed to it, we knew
15 that going in. If you ran solution-based defects on
16 that I suspect others would show benefits on that. But
17 those are not the rules of the game, we understand that.
18 But the causation is the method to apply costs to us; it
19 should also be the method to apply to RTEP charges.

20 So I would offer to you that if at the point
21 of time that we entered into our interconnection
22 agreement, everything else in the PJM system was frozen
23 the exact same way we were, we can't change without
24 asking for an interconnection upgrade to the cost. If
25 everything was frozen there would be no need for RTEP

1 upgrades. The only thing you would need would be to
2 reinforce and replace old expiring equipment. All the
3 other RTEP is for expansions and changes that are
4 happening in the system which we cannot constantly be
5 causing since we're static. We can only change if we
6 come in with another interconnection request.

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

25 Steve made the comment, it's very hard,

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

11 I also suggest that you run it without the
12 ConED wheel, without us, without the FTWR's, the short
13 circuit is going to be there, and indeed the upgrade is
14 still going to be there. So we could not possibly be
15 the reason from the need to solve that short circuit
16 problem. For that reason, the defects method is clearly
17 not the appropriate solution for something like a short
18 circuit problem. We did talk about the economics a
19 little bit on the MTF on the next page. On the
20 right-hand side for this PSEG projects of what our cost
21 allocation would have been if it was a hundred percent
22 load ratio share. The two mailboxes are the cost
23 allocation -- the center one is the PJM cost allocation
24 of ConEd and the wheel, and then there's a question to
25 have that determination made with ConEd no longer in the

1 wheel, and it shows the cost allocation to Hudson. The
2 bottom line is my attempt to make some gross estimates
3 and take them for what they are as to what the annual
4 transmission revenue requirement would be that Hudson
5 would be billed from PJM, and that number ranges from 18
6 million to 100 million dollars, annual number. In order
7 to recoup that cost, the price of capacity of PJM would
8 have to decline by 153 dollars per megawatt day to \$850
9 per megawatt day for us to recover those costs that we
10 would be allocated to.

11 I can tell you one thing for certain: The
12 nature of this RTEP cost allocation absolutely makes it
13 impossible to mobilize capital for merchant transmission
14 projects and it also puts the shareholders in my two
15 companies in a position where they absolutely have to
16 seek any means they possibly can to just try to save
17 their existing investment. Amy brought up on the next
18 page some concerns; I just want to raise questions about
19 these. From my comments here you can see that I don't
20 think that solution-based defects at all is an
21 appropriate allocation for these types of projects in
22 merchant transmission. But I also just ask general
23 questions: On the one percent de minimis rule, if
24 there's a TO that's shown to use 100 megawatts of
25 facilities and we're shown to use six why do we get

1 costs and they don't? And then when there's a gross of
2 that, we actually have to pick up their cost? That is
3 hard for me to understand the rationality on that. And
4 then if we look at the netting on situations there and
5 de minimis all mixed together, you could have say a 400
6 megawatt facility, maybe Hudson got allocated 5
7 megawatts and TO got allocated 45 megawatts. If that TO
8 is GPNO, I got responsibility of 10 percent of the
9 project. If that TO is 80 P or PSEG, I now have
10 responsibility for 80 percent of the cost. Someone has
11 to help me understand why my benefits went up 10 times
12 in that second scenario.

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

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

24 MR. LeCOMTE: Thanks, Jeff.

25 Mark?

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

25 I wish to emphasize that ODEC believes that

1 the solution-based defects continues to produce
2 reasonable cost allocations for the overwhelming
3 majority of PJM RTEP projects. Since solution-based
4 defects went into effect in early 2015, however, we want
5 to see a small number of RTEP allocations produced by
6 solution-based defects do not reasonably align with the
7 customers who can expect to benefit from those RTEP
8 projects. ODEC was directly impacted by these
9 solution-based defects when PJM agreed to several RTEP
10 projects with the artificial island in New Jersey.

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

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

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

13 Looking at the artificial island project in
14 particular, the primary component of this project is a
15 230 KB transmission line, as mentioned before by
16 Southern New Jersey and the State of Delaware. This 230
17 KB line will help resolve the generator issues at
18 artificial island, that has been clearly stated by PJM,
19 but is not required to resolve any thermal or voltage
20 reliability criteria violations that might be caused by
21 load growth in the Del Marva zone since there is no
22 violations from the Del Marva zone that may be resolved
23 by this 230 line. Because the stability problems at
24 artificial island are attributed in part of limited
25 transmission pass at artificial island area, it's only

1 been inevitable that solution-based defects would simply
2 advocate the cost of a new transmission line out of
3 artificial island to the PJM zone in which the new line
4 happened to terminate. So if the line had gone to D.C.,
5 the D.C. folks would have been the cause; if it went to
6 New Jersey, New Jersey people would have been paying the
7 cost. It's just the fact as solution-based defects is
8 utilized.

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

24 PJM matrix itself is evidence that PJM can
25 readily break out RTEP projects by reliability planning

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

17 However, if the operational performance
18 upgrade are driven by a non-flow based criteria such as
19 stability concerns are the project should be considered
20 for alternate cost allocation methodology. That leaves
21 the Commission's question on whether an alternate just
22 and reasonable ex-ante cost allocation methodology could
23 be established for the categories and facilities where
24 solution-based defects could not be relied upon. That
25 would require a conference on whether alternate

1 methodology or methodologies can be developed.

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

12 MR. LeCOMTE: Thanks, Mark.

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

18 I originally put into the agenda a break for
19 11:40. We're a little bit ahead of that. So I'm going
20 to take a break now; it's not a longer break, just an
21 earlier break. So I'll come back at 11:40. Thanks.

22 (Whereupon a short recess is taken.)

23 MR. LeCOMTE: Okay, if we can get started.
24 Two things I want to ask: I've been able to turn my
25 volume down on the phone, but the feedback I hear is

1 that people are still either typing away or shuffling
2 papers, and it's disruptive to those who are trying to
3 listen. So please, telephones on mute if you're
4 listening.

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

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

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

1 so.

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

13 This is clearly a unique situation; whether
14 it will ever happen again is really hard to venture.
15 But it's a combination of things which I couldn't even
16 begin to dissect everything's that has happened in the
17 last 10 years that may have led us to a situation where
18 we had to balance either the inability to control
19 voltages with the stability of the station, three large
20 nuclear generators, and it would take a lot, a lot of
21 work to back up in time. It's easier to see with short
22 circuit because there are really decreased changes to
23 the grid that add short circuit duty at a particular
24 location with the stability at artificial island. It
25 would take a lot of work for us to go back in time and

1 try to identify every change that has taken place in the
2 last 10 years, five years, whatever, and say that made
3 the problem worse, that made the problem a little will
4 worse. And we haven't attempted to do that, okay.

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

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

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

24 MR. LeCOMTE: Somebody without the
25 microphone.

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

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

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

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

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

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

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

24 MR. HERLING: They may or may not but
25 they're readily calculable. The point is that the

1 initial benefit of solving the problem fades over time.

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

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

19 MR. LeCOMTE: So if I were to look at the
20 matrix that you've given us, and while I know there are
21 some stakeholder issues identified for the different
22 groupings that you've provided, that by and large the
23 solution-based is supported for flow-based or thermal
24 and voltage type reliability concerns. And you've
25 identified several groupings of reliability concerns,

1 okay: The short circuit; the stability type issues;
2 aging infrastructure. What would you think of
3 identifying beneficiaries for this other group that
4 you've classified in the matrix?

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

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

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

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

20 If you look at Atlantic City Electric, which
21 is right where the plant is, or Del Marva or Pico, those
22 are the zones closest, they would have the biggest
23 problem if you had a stability problem. And in the
24 short circuit analysis that was referred to, that's
25 where you see the biggest delta in the LMP's, okay. So

1 there are analytically ways to establish which zones are
2 most impacted by the stability. The challenge again is
3 how much weight do you put on that when you compare it
4 to the use of the facility that has been built to
5 resolve the problem.

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

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

24 If a project is approved by the PJM Board
25 because by itself it satisfied the market efficiency

1 standards, then there's a method for allocating those
2 costs. And that's pretty straight-forward, and it is
3 based on where the LMP's are reduced. And if there are
4 RPM benefits, there are various ways of looking at the
5 benefit of the project. But today there is no way to
6 just grab those coincidental market efficiency benefits
7 and attribute them to the cost allocation.

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

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

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

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

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

24 MR. SASSON: I just want to say that we
25 think that these issues are rare, and we've already said

1 why they're rare. It's very rare that a short circuit
2 is being resolved with a transmission; it's very rare
3 that storm hardening is being resolved with a
4 transmission; the transformer. So given that these are
5 rare, we try to answer the two questions that you asked
6 in a very direct manner. These are rare but they're in
7 a different category, right, there's no overloads here.
8 And if they're rare and they're in a different category
9 and we know where they are, what happens what Peter was
10 saying the "where", the zone, that's where you should
11 cost allocate it.

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

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

25 MR. SASSON: In my opening remarks I said if

1 we have a stability violation it's because Steve, these
2 people, Steve's people, analyzed a stability situation
3 and said, "Ah, if something happens, we have in the
4 system, some units, even if it's rare, some units are
5 going to lose stability." We have a stability
6 violation, there's a rule that says when that happens
7 you got to do something about it. Sometimes you can
8 just do controlled, which is what he said. It should
9 have been caught in the connection process, he said. So
10 very rare you're faced in -- maybe never comes up, as
11 Steve said -- you got the transmission issue to address
12 the problem. But once you got a transmission line to
13 address the problem, then where are the units that felt
14 the stability issue? In the zones where the units that
15 felt the stability problem, that's where you should go.
16 And that's the "where."

17 MR. LeCOMTE: Okay, thanks.

18 Jeff or Amy?

19 MR. WOOD: Just I hate to go back a little
20 bit. I want to talk about short circuit and comments he
21 made right before we broke. I want to clarify the
22 record a little bit. Esam's comments were on the short
23 circuit that Hudson was causing the problem. And I
24 would acknowledge that when we were studied we caused
25 some short circuit problems, but we paid for all the

1 solutions at that time to resolve the problem. We spent
2 roughly 30 million dollars to entirely build out a new
3 substation for them at the 80 KD level, probably
4 creating a little bit of headroom in there. And this is
5 before VLC was ever even contemplated.

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

8 MR. WOOD: Go to Amy.

9 MS. FISHER: I just have two short comments.
10 The first is that PJM has several formulas in Schedule
11 12 which have a series of different pieces that need to
12 be accumulated together, I'm thinking of the multivalued
13 projects, which determines beneficiaries and how
14 different cost allocations are going to be added up and
15 allocated. So there's the public policy piece, that
16 goes to the state; there's the market efficiency piece,
17 that goes in the accordance to 1.25 to one formula; and
18 then there's the reliability piece which is allocated
19 based on solution-based defects. This is not a one size
20 fits all, there's no reason why you can't count up all
21 the beneficiaries in each of their different ways and
22 cost allocate. Yes, it's a little more complicated, but
23 the alternative is simply to have a formula that doesn't
24 work for ex-ante purposes.

25 And I would just make one more comment,

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

6 MR. LeCOMTE: Thanks.

7 Frank or Takis. Mic, please.

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

22 Again, any causation type approach would be
23 a one-time calculation, you have to decide what you do
24 to the parties that came before the incremental
25 violation was created, and then the parties that come

1 later that benefit from the fact that the project was
2 there would have contributed to that short circuit
3 problem that are not paying for that project, so you're
4 creating a free ridership.

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

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

22 MR. LeCOMTE: Thanks.

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

25 MR. WEISHAAR: Yes, thank you.

1 A few comments. (1) On the total benefits
2 associated with the project, when PJM ran its market
3 efficiency study for artificial island it showed that
4 the total LMP, just LMP -- related benefits of the
5 project, were around the order of 169 million dollars,
6 and that was just a one-year snapshot. So when you're
7 looking at sort of return on investment and cost benefit
8 ratios over time, and looking at an estimated cost of
9 275 million dollars on the artificial island project,
10 and if you take an economics-based allocation, the zones
11 can look at this on a return-on-investment-type basis
12 where they get the benefits associated with the cost
13 responsibility for that particular project.

14 When we looked at -- we have two issues
15 today: One is the definable category, and I think it's
16 getting pretty clear and clearer that artificial island
17 falls into a definable category. It is a
18 stability-based project, there is one of 1,200. The
19 second issue is a little more challenging, and we
20 thought about what is the appropriate approach for cost
21 allocation? It is a reliability-driven project, but
22 coming up with an objective quantifiable, independent,
23 neutral approach for quantifying the reliability
24 benefits is extremely difficult. So we got to sort of
25 the next step of what are the other options? We looked

1 at the Con Edison approach of a load ration share. That
2 load ratio share in the context of artificial island
3 would likely result in a hundred percent of the costs of
4 artificial island being allocated to the PSEG zone,
5 which raises equity issues in the reverse. Because when
6 you look at the LMP benefits, only 16 percent of the
7 LMP-related benefits inner to the benefits of the PSEG
8 zone. So you would have almost the reverse of what the
9 Del Marva zone is facing today. So that raises its own
10 set of equity issues.

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

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

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

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

24 MR. WEISHAAR: We have not taken obviously a
25 thorough look into the short circuit issues because what

1 we're facing in the Del Marva zone is a stability-based
2 project. So we have not taken a position, I think
3 that's for the other parties to discuss and address.

4 MR. LeCOMTE: Sure.

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

8 MR. HERLING: I think we're going to need to
9 clarify some of the market efficiency analyses that is
10 being discussed. A traditional market efficiency
11 analysis, when we look at a new transmission project,
12 would be to model the system with the line in place and
13 without the line in place; and we did perform that
14 analysis some time ago. I don't remember the numbers,
15 but I'm fairly certain the numbers that Bob was
16 referring to was related to a market efficiency analysis
17 that Delaware specifically asked us to perform, which
18 was to compare the system as it is today but with one
19 nuke turned off to the system in the future with the new
20 line and all three nukes running. The premise being
21 that without the solution the probability of one nuke
22 needing to be turned off would be increased potentially
23 over time. So the large deltas that were observed were
24 as much or more a function of one of the nukes being off
25 as they were of adding the line to solve the stability

1 problem. So that is not a traditional PJM market
2 efficiency with a capital M, capital E, analysis. It is
3 a means of identifying certainly the LMP impacts of the
4 stability of the unit.

5 MR. LeCOMTE: For what was specified?

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

13 Now, to your other question, if we were to
14 start running market efficiency analysis to look for the
15 ancillary benefits of every reliability solution, first
16 of all, that would be a tremendous amount of work. I'm
17 not sure to what extent it would show us a different set
18 of beneficiaries than the parties who are flowing in the
19 direction of the new line anyway. Today we do, with the
20 new cost allocations, an analysis to show how many hours
21 the flow is in one direction versus the other; that's
22 part of the solution-based defects analysis, it's
23 essentially a weighting mechanism. If the flow is
24 50/50, 50 percent north, 50 percent south, then we
25 attribute benefits at both ends of the line equally. If

1 it's 90/10, obviously the primary direction of flow is
2 where most of the benefits are. So we do that analysis
3 but it's based on the system as it exists moving forward
4 to, I think it was Takis' point earlier, if we were to
5 try to do a traditional market efficiency analysis where
6 we actually wanted to see the benefit of the line
7 itself, that would mean removing each line that we have
8 approved over years and years one at a time and looking
9 at do you unwind the system to the conditions that were
10 in place 10 years ago? That would be an enormous amount
11 of analysis. So I wouldn't suggest that that is doable
12 in any reasonable fashion on a repeated basis. Somebody
13 made the comment that we could do that analysis; I don't
14 think that's possible.

15 MR. LeCOMTE: Thanks.

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

18 MR. RICHARDSON: Thank you and sorry to move
19 back a little bit. You started off with some comments
20 from the merchant transmission owners. The merchants
21 have made quite a bit of the fact that they're
22 different, they need to be treated different, they need
23 special rules, it's a different context for them. And I
24 think it's really important for us to understand that
25 that question has been answered by FERC. And the PJM

1 transmission owners in executing the cost allocation we
2 have to follow the FERC order, it's Opinion 5 or 3
3 maybe, (a) I think. But that opinion basically says
4 when it comes to the merchants they need to be treated
5 like any other zonal load.

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

18 MR. LeCOMTE: Thanks.

19 Esam?

20 MR. KHADIR: Thank you. I just want to make
21 a couple points regarding the market efficiency analysis
22 that the Delaware Commission had asked PJM to do. The
23 Delaware Commission has regarded the issue, and the
24 scenarios are basically unrealistic scenarios. For
25 someone to assume that one of the selling units can be

1 out for a whole year, that's -- I've been working with
2 PSEG since 1976, about the time that those units were
3 put in Commission. And up until now I have not seen one
4 of those selling nuclear units out for a year was of
5 stability issues, and I don't believe that they will be.

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

16 Now, PJM, as they were doing their
17 comparison, the proposal comparison analysis for
18 artificial island, they performed a market efficiency
19 analysis according to the assumptions developed by TIEC
20 (phonetic). And reviewed those assumptions with TIEC.
21 The results from that market efficiency analysis shows
22 that there is about 90,000 to a million dollar worth of
23 benefits over 15 years, and all of that 90,000 to a
24 million dollars, a percentage of that 90,000 to a
25 million dollars, were to the Del Marva zone. Now, that

1 is real assumptions that we use to develop market
2 efficiency, the best case that we use to develop market
3 efficiency results, and that's the results that you
4 should be using.

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

13 MR. LeCOMTE: Thanks, Esam.

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

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

18 If I could just briefly respond to this
19 issue that's coming up today in terms of it's acceptable
20 to impose the solution-based defects and suspend the
21 requirement for roughly commensurate benefits because
22 over time somehow the benefits will inert. And I find
23 it hard to accept that there are characteristics in the
24 Del Marva zone that would somehow shift that 99 percent
25 cost responsibility to the artificial island facility

1 any appreciable amount over 30 years.

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

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

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

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

15 Steve, I got another curiosity for you as we
16 talk about the reliability concerns, and especially we
17 talked about the allocation of short circuit and the
18 majority, the vast majority, to the zone. And I think,
19 if I understand correctly, those are somewhat discreetly
20 identified reliability concerns where you can address
21 the concern. To the extent we have -- and you've
22 identified in the dockets that you have under short
23 circuit a short circuit problem, I suspect that that's a
24 -- short circuits may be the primary driver of the
25 project, but that there are other reliability issues

1 that are being addressed in that project in particular.

2 But I want to talk about it in a generic sense.

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

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

18 MR. HERLING: Correct.

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

23 MR. HERLING: Well, we don't attempt to
24 establish any defects for those problems. You can't
25 realistically perform -- I suppose you probably could,

1 I'm not sure what it would tell you, for replacing a
2 circuit breaker. But because the allocation is to the
3 zone, we don't actually perform the calculation; there's
4 no reason to. When we have a single circuit breaker
5 that needs to be replaced and the cost is \$300,000,
6 because we know the reallocation is to the zone there's
7 no reason to even attempt a defects calculation. It's
8 only -- this is, as I said, the first time we've had to
9 do it and it's because the solution was in a line. And
10 in particular now we have a defects calculation that's
11 based on the use of the solution and is really divorced
12 from the nature of the problem that required the
13 solution.

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

20 MR. LeCOMTE: Thanks.

21 Mayer, did you have a comment, please?

22 MR. SASSON: Just a very brief comment, Ron.

23 And your questions were more on short circuit.

24 I want to go back briefly to storm hardening
25 questions. And the fact that if you try to apply

1 solution-based defects to that -- which has been done --
2 you get results, somebody already said "strange", but
3 it's more than strange. You fix a substation, you build
4 some lines, those substations have loads, and it turns
5 out that the owner of those substations and serving
6 those loads actually paid not even one dollar, not even
7 one penny for it. So it turns out that you apply the
8 method and it turns out that Con Edison and Linden would
9 pay a hundred percent of that, and yet the owner of the
10 facility, the zone where that facility is, is allocated
11 zero dollars. And that cannot be. That's why I go back
12 to the: It's the zone that needs to pay, that's the
13 zone that has the benefit.

14 MR. LeCOMTE: Thanks.

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

19 MR. HERLING: Which category was this?

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

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

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

23 MR. HERLING: Correct.

24 MR. LeCOMTE: So for those types of
25 operational concerns the beneficiaries are appropriately

1 identified through the solution-based defects?

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

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

17 MR. HERLING: Well, it could. The nature
18 for a stability problem is that for a particular fault
19 that you apply on a system, the power plants, the
20 generators, will swing and trip off the system because
21 they lose synchronism. In the case of artificial island
22 it was a combination of issues where if all of the units
23 were running and we saw operational situations where we
24 had high voltages, we would have to change the reactive
25 output of the units which would move them into a

1 condition where they became unstable. So you were
2 fighting one operational solution against another. And
3 ultimately we pursued a solution of a transmission line
4 to improve the stability. The original nature of the
5 problem is the rotational inertia of the generators;
6 they were unstable for certain faults. So it's not like
7 an operational performance issue which is related to
8 flow two-load in an isolated pocket that looks just like
9 a thermal overload and you can treat it for a solution;
10 for cost allocation pretty much the same way.

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

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

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

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

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

1 analysis or studies?

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

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

19 MR. HERLING: Well, for the time being, we
20 would address it in the same fashion. We would look for
21 the most affective transmission solution, assuming that
22 there were no easy control device solutions. Including
23 a stabilizer on a plant is a fairly cheap solution, and
24 we've done that before to resolve at least one problem
25 in the past. So assuming there is no cheap control

1 device solution, we would look for a transmission
2 solution, we would look for the most cost-affective
3 solution, we would ask the Board to approve it, and we
4 would apply the cost allocation as it exists today,
5 which iis based on solution-based defects.

6 MR. LeCOMTE: : Okay.

7 MR. ROLASHEVICT: Thanks, Ron.

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

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

13 MR. ROLASHEVICT: Yes.

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

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

24 MR. HERLING: I think was the grid is aging
25 you will see more aging infrastructure projects. I

1 don't know whether we're going to see more
2 storm-hardening projects; obviously, Hurricane Sandy was
3 a pretty big deal. I don't know how much is left out
4 there that we may find needs to be improved in that
5 fashion.

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

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

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

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

1 solution-based defects.

2 MR. ROLASHEVICT: Thank you.

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

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

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

25 MS. TEETER: Short circuit and projects

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

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

17 Short circuit is harder in that respect
18 because every generator added everywhere will contribute
19 to the problem, maybe in very, very small amounts.
20 Every transmission line you build will bump up the short
21 circuit duty, again, maybe by very, very small amounts,
22 but it's something we study every year. But as a
23 breaker approaches its capability, we view it as not
24 being a problem. When it reaches its capability then
25 it's a problem. So if you want to look back over time

1 we can see situation trending, but until you anticipate
2 the need for the next big transmission line or the next
3 generator building close by, you don't know when you
4 might trigger that violation.

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

14 MR. LeCOMTE: Thanks.

15 MR. RICHARDSON: Frank Richardson with the
16 transmission owners.

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

1 230 KB line into their zone with 3,800 megawatts
2 attached to it and they're getting a substantial amount
3 of the cost for that project. On the surface and face
4 value, that would make sense.

5 MR. LeCOMTE: Thanks.

6 Pass the mic down. Amy, please.

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

20 However, what I would say is that there are
21 benefits and there are incidental benefits. If the
22 purpose of the upgrade is not to improve the way you use
23 the system but you nonetheless benefit in some amorphous
24 way, then that's why we have load share and the 50
25 percent of the project costs that are borne by load

1 share. And I believe that's what Chip was just
2 referring to. That doesn't mean that every person who
3 incidentally moves power over the line should be cost
4 allocated the same way that people for whom the blow-up
5 of the transformer or the breaker is really what's being
6 sought for.

7 MR. LeCOMTE: Thanks.

8 Mayer?

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

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

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

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

25 But what I wanted to answer your question

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

19 MR. LeCOMTE: Thanks, Mayer.

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

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

24 Two observations: Obviously we're here
25 trying to figure out why these cost allocations look as

1 maybe blatant to some folks as compared to other cost
2 allocations. But I want to throw two additional
3 observations that we may want to take into
4 considerations. As far as the merchant entities that
5 were cost allocated, the projects in question here is
6 that the cost allocation would be dramatically different
7 to recognize that they're a single-load zone. If they
8 were got a single-load zone, if that load was part of
9 the host zone of the larger zone or the one that they're
10 interconnected with, the cost allocations would be
11 dramatically different. So the phenomenon that is a
12 single load zone is a consideration.

13 Regarding the Del Marva cost allocations, we
14 noted that's where the physics are putting the flows and
15 solution-based defects measures those. So for this
16 particular project it's not surprising by looking at the
17 map as to where the project is going; it's not
18 surprising whose megawatts are flowing on that. But at
19 the same token, there are lots of other projects
20 throughout the rest of the PJM system the solution-based
21 defect sees to it that the Del Marva Peninsula does not
22 get cost allocated for those projects because, again,
23 from a locational point of view the Del Marva load is
24 far electrically away from those facilities. So
25 basically, because you have one project here that may

1 look maybe disproportionate in some eyes, you also have
2 to take into consideration the other projects where the
3 Del Marva loads are not picking up any cost allocation.

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

14 MR. LeCOMTE: Thanks.

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

17 MR. GROSS: Ed Gross from staff.

18 Question directed to Mr. Herling. It's kind
19 of a thought experiment, actually, what I want to
20 suggest, and an uncomfortable one at that. Assuming
21 arguendo that a short circuit problem exists on the
22 system which for some reason PJM missed, and a bad thing
23 happened and we go well beyond what happens as far as
24 for flows for the breakers themselves and we pass our 80
25 KA position, could you describe some of the effects that

1 may have? Well, let me just ask you straight-up would
2 probably be easiest. Short circuit problems that would
3 happen would affect the system in general, the breaker,
4 the connected facilities around that system, whereas
5 possibly sounds like stability problems affect the
6 generators and have more implications for the operations
7 of the generators, would that be an accurate statement
8 in your minds?

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

17 We've had some pretty significant system
18 events that started out as stability problems. With
19 short circuit, if you had a fault that exceeded the
20 capability of a circuit breaker, either it's 80 KA or
21 any size, it could be restricted literally to that
22 substation. The breaker blows up a couple of lines open
23 and that's the extent of the problem, or it could then
24 cascade where you have lines overloading and more lines
25 tripping, you could have local stability -- it could

1 cause local stability problems on generators. And,
2 again, depending upon circumstances if things go badly,
3 it could cascade into a much more severe event. More
4 than likely in both cases it's going to be very
5 localized, but sometimes bad things happen. So it's
6 possible that it could extend beyond the local area.

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

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

20 MR. GROSS: Thank you for your answer.

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

25 (Whereupon a short recess is taken.)MR. LeCOMTE: Okay,

1 we had a few followup questions. Steve, I just wanted
2 to see if you wanted to follow up on some of the earlier
3 conversation?

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

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

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

22 MR. LeCOMTE: Okay, thanks.

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

25 MR. LeCOMTE: Just as a general thought,

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

3 MR. HERLING: They were not.

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

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

13 MR. LeCOMTE: Thanks.

14 Mayer, did you have a --

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

25 MR. LeCOMTE: Thanks.

1 Val?

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

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

15 MR. HERLING: We were trying in that column
16 to represent issues that various other parties have
17 raised in a reasonably fair basis. That was a cost
18 allocation question that had come up at one time; it was
19 never really dealt with. But the obvious question is:
20 If you simply replace something in kind -- which happens
21 all the time, transmission owners maintain their own
22 facilities and often have to replace circuit breakers or
23 transformers of even parts of transmission lines -- if
24 they replace them in kind, you may view that one way; if
25 they replace it with something bigger and better and

1 provides all kinds of additional capability, you may
2 view it differently. And the question arose sometime
3 ago: Should you kind of bifurcate and treat the
4 original capability one way and the incremental
5 capability a different way? But that's never actually
6 been dealt with beyond having been raised.

7 MS. MARTIN: This is Valerie Martin for
8 FERC.

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

20 MR. HERLING: Sure. I was describing two
21 categories of benefit. One was just the pure use of the
22 facility. All load needs to be served by energy; the
23 energy has to get from generators to the load. So the
24 transmission facilities that allow for that transfer of
25 energy provide a benefit to that load. So if you build

1 a new line and two zones make use of it to serve their
2 customers, then they are clearly benefitting by its
3 existence.

4 What I was suggesting was that the initial
5 -- this goes back to when we used violation-based
6 defects -- we then described the beneficiaries as the
7 parties who caused the problem because the elimination
8 of the problem returned the system to a reliable state.
9 And those customers who previously had placed the system
10 at risk are now benefitting by the system no longer be
11 at risk. So the causers were the beneficiaries by the
12 elimination of the problem. Now we use solution-based
13 defects. Part of the rationale for solution-based
14 defects was that for the vast majority of projects the
15 users of the new facility are very similar to the
16 causers of the initial problem. And if you think about
17 flow from A to B, if you have -- people causing flow
18 from A to B, if there's a violation, when you build a
19 new line it's typically going to be in parallel with A
20 to B and the people who caused the problem from A to B
21 will now use the new facility, so the causers and the
22 users after the fact are largely the same. So for 99
23 percent of the projects -- whatever the percentage is,
24 I'm just throwing out a number -- we believe, PJM
25 believes, that you're capturing both the causers and the

1 users generally through solution-based defects. Where
2 that doesn't quite work is when you have a short circuit
3 problem or a stability problem -- because the users in
4 the case of the solution to artificial island, you're
5 solving the problem by building one more line, in this
6 case from artificial island down to the Del Marva
7 Peninsula -- you could have also built a line to
8 Philadelphia or you could have built a line to Allentown
9 or you could have built a line to Newark, New Jersey,
10 and you would have solved the stability problem, and the
11 users of that new line would have been noticeably
12 different, okay. None of that use is the entire picture
13 of who caused the problem.

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

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

25 MR. HERLING: Over time the use of the line

1 tells you a lot about the benefits of that single
2 solution. My point earlier was 30 years from now when
3 one of the Salem units have retired, there will no
4 longer be a stability problem, but the line will still
5 be there and the line will still be serving a purpose
6 and it will still be providing benefits. So the initial
7 who-caused-the-problem beneficiaries will evolve over
8 time.

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

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

25 MR. HERLING: That's one addition. You got

1 to decide whether that's a big enough issue to solve.
2 We're talking about a couple of projects here. I
3 realize it's a lot of money, but if we never have
4 another stability problem ever again, okay, we can
5 create a different solution, a different cost allocation
6 solution, okay. I would like to keep it reasonably
7 simple, we could come up with a different approach that
8 blends in other types of beneficiaries. But honestly I
9 wouldn't expect it to be used very often.

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

12 MR. HERLING: Oh, sure.

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

18 MR. HERLING: Yes.

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

22 MR. HERLING: Actually, because we're using
23 solution-based defects, this is one of the huge benefits
24 of solution-based defects. Somebody's mentioned the
25 Roseland project which had dozens, it might have been

1 four dozen problems, that were resolved by Roseland.
2 That's a 500 KB line and it was socialized. But to do
3 cost allocation based on 48 or so individual violations
4 and then weight them all and put them all back together
5 then would have been a nightmare. With solution-based
6 defects you don't need to do that; you have one solution
7 that solves 50 problems; you have one cost allocation
8 based on who uses the solution; not who caused each one
9 of the 50 different problems. That's a huge advantage.
10 That was one of the big reasons, that and the ability to
11 redo the allocations every years based on changing
12 system conditions. Those were the big advantages of
13 moving to solution-based defects.

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

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

19 MR. SASSON: Valerie, you asked a number of
20 important questions here. You asked a number of
21 important questions here, and I want to make sure that
22 it's clear that in my answer that we're not advocating
23 for violation-based defects. That has to be absolutely
24 clear, we said that from the very, very beginning. And
25 I think Steve is saying for thermal overloads the

1 solution-based defects is something that can be
2 reproduced year by year over time. It makes sense
3 because the users of the solution are the same as the
4 causers, and there's consistency as we discussed. But
5 we're here to answer the first question that the
6 Commission asked: Is there a category of projects that
7 are based on non-flow, not flow-based but non-flow? And
8 I think we've answered that there are, there is a
9 category of projects that have various -- depending on
10 the nature of the problem, it could be storm hardening,
11 it could be short circuit, it could be stability. So
12 there a number of them. The question, then, is: Once
13 you solve it with transmission, because there has been a
14 violation, storm hardening, something got broken,
15 there's a violation, now you solve it. The question
16 being asked here to some extent is: Do you just cost
17 allocate a little piece to whoever is the one that had
18 the problem? And then later on you charge other people.
19 And I'm not sure that's fair because the issue was the
20 storm hardening.

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

1 exact way of doing it.

2 MR. LeCOMTE: Thank you.

3 Takis?

4 MR. LAIOS: Takis Laios, PJM transmission
5 owners.

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

22 Today we don't have any carveouts.
23 Essentially you're looking at the solution based-defects
24 which measures where the physics are placing the flows.
25 So that would be, again, just a cautionary observation

1 as to if we embrace these two as being unique that
2 that's going to open the door to a third driver is also
3 unique and should be included with these other two. So
4 I appreciate that.

5 MR. LeCOMTE: Thanks, Takis.

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

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

15 MR. HERLING: : That's a trickier one.
16 Stability, it's at least analytically, you can visualize
17 the impact of a stability problem geographically. I can
18 imagine a test. I'd have to talk to my engineers, but I
19 can imagine a test that would show me where the impact
20 dwindles to some de minimis level. Short circuit, I'm a
21 little bit stumped. I'd have to think of how that would
22 look like. I suppose you could look at the impact of
23 generators, for example on a short circuit problem and
24 the further away you get, that impact reduces to some de
25 minimis level. But now you're associating the physical

1 location of generators with the local load, which in a
2 market environment there is no direct relationship
3 between a generator and New Jersey and the load that
4 lives right around it. So we'd have to think about what
5 those implications might be; I don't have a good answer
6 for you for short circuit.

7 MR. LeCOMTE: Thanks.

8 And Amy?

9 MS. FISHER: So I have to quote Maynard
10 Keynes, which in our case is very appropriate because in
11 the long run we are all dead. And I don't mean that for
12 us as mortal beings, although it's true in that case as
13 well. But I mean it in terms of the companies we
14 represent sitting here. The fact that in some
15 alternative universe we will be able to recognize the
16 benefit of a 1.2 billion dollar project is really, very
17 cold comfort for a company that's faced with costs that
18 are simply in excess of its revenues. I think that if
19 the ex-ante formula that we're trying to solve for is
20 important to people, then it needs to work, not most of
21 the time but all of the time. So we can make that
22 happen in two different ways: We can either take the
23 time and effort and not say "it's complicated" or "maybe
24 we won't use it very much", to try to get that ex-ante
25 formula as close to correct all the time as we possibly

1 can; or when it doesn't work the people who are affected
2 are going to come to FERC or the courts to get redress.
3 And I think those are the questions we need to answer
4 here. And failure to really dig hard into this formula
5 means that's how it's going to be addressed in the
6 future.

7 MR. LeCOMTE: Thanks.

8 Esam?.

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

1 MR. LeCOMTE:: Thanks.

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

8 MR. LAIOS: There, at least in my mind,
9 needing to take aback, obviously I'm representing the
10 PJM transmission owners here. My response to that
11 question would be basically all the other items we're
12 talking about here, we're talking about requirements
13 that apply to the entire PJM footprint. NERC
14 reliability standards apply to the entire footprint; PJM
15 planning procedures apply to the entire footprint. In
16 that particular situation you're talking about something
17 that applied to one zone. So therefore I view, at least
18 in my case, differently from the carveouts that we're
19 talking about here. Here you're talking about a short
20 circuiting that can happen anywhere in PJM in order to
21 address a requirement that PJM applies consistently
22 throughout the PJM footprint. While in the other case
23 you're talking about a particular local transmission
24 entity choosing to -- because of unique needs that they
25 may have in the local area, have essentially a driver

1 that's unique to that zone. So it's not whether it's
2 short circuit thermal or voltage, but what is the need
3 that that particular entity's trying to address in their
4 particular zone.

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

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

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

22 MR. LeCOMTE: Thanks.

23 Mayer?

24 MR. SASSON: Today I find that I have agreed
25 a lot with what Steve has said except this time. Now I

1 disagree with him. The end-of-life violation that you
2 mentioned of a particular line. Who caused that
3 violation? That's the question we need to ask
4 ourselves. Is it the load that was using the flows that
5 were going to certain loads? Did they cause the end of
6 life?

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

14 MR. SASSON: Ron, I fully agree with you
15 that solution-based defects over a transmission line
16 will identify the users; that is a given. However, that
17 is not the real question I think we should be asking
18 ourselves, which is: Why are we doing the project? And
19 if you have an end of life, this line has been there for
20 40 years, is breaking apart, etcetera, we can't rely on
21 it anymore, we got to replace it. Whether we are
22 replacing the line or we are redoing it, we might as
23 well do a better line so we have more capacity line for
24 the future.

25 But was that the purpose of the line, to

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

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

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

21 MR. LeCOMTE: Thanks.

22 Okay, I think I want to start by finishing
23 by saying I appreciate all of the panelists, all of the
24 comments, and in particular all of the people who have
25 sat in the room and listened to quite a long dialogue

1 about the Commission's questions here and the comments
2 that we heard. I really do appreciate all of the
3 participation today, and while I said I don't speak for
4 the Commission, I think the Commission would support
5 that comment. Thanks everybody.

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

19 (Whereupon the FERC technical conference scheduled for
20 10:00 a.m. on January 12th, 2016, is concluded at
21 3:30 p.m.)

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