UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Within The California Independent System Operator Corporation	Docket No. AD18-12-000
California Public Utilities Commission, Northern California Power Agency, City and County of San Francisco, State Water Contractors, Transmission Agency Of Northern California	Docket No. EL17-45-000

v.

Pacific Gas and Electric Company	
Southern California Edison Company	Docket No. ER18-370-000

TECHNICAL CONFERENCE

Federal Energy Regulatory Commission

888 First Street, N.E., Room 1

Washington, DC 20426

Tuesday, May 1, 2018

9:00 a.m.

SPEAKER LIST

Laura Switzer-Moderator

Linda Kizuka

Neil Millar

Jordan Pinjuv

Jeffrey Nelson

Noman Williams

Jonathan Newlander

Will Speer

David Gabbard

Chris Thomas

Katherine Mapes

Traci Bone

Dave Dockham

Brian Griess

Dana Cabbell

Valerie Teeter

Maria Farinella

Geneva Looker

Angela Amos

Danielle Gordon

Jocelyn Wong

Mark Patrizio

Michael Haddad

Gary Chen

SPEAKER LIST (Continued)

MONICA TABA

FRANKLIN JACKSON

GREGORY PRICE

P R O C E E D I N G S

MS. KIZUKA: Good morning and welcome and thank you all for coming today. I'm Linda Kizuka from the Commission's Office of General Counsel and before I begin our session I just wanted to briefly mention the Commission's ex parte rules so that we're keeping them in mind as the day progresses.

The Commission's ex parte rules apply to on the record contested proceedings and that means we can't discuss matters that are currently pending before the Commission. Should it appear to staff that the discussion begins to get into the merits of a contested issue or a pending matter we will redirect the conversation.

If, during the course of the Conference you're concerned about a response you are providing or a question you're asking may run afoul of the ex parte restrictions, please let us know.

If we're unable to provide an answer immediately to confirm whether a response would be covered by the ex parte rules, we will table the discussion and respond to it once we've had an opportunity to more fully consider the issue.

Thank you for being mindful of the ex parte restrictions as we move forward today. I'd also like to note that as reflected in the list of questions provided in

the April 10th supplemental notice, the focus of the discussion today is the processes, the PTOs in CAISO used to determine whether an activity or project should be submitted to the CAISO transmission planning process.

Out of an abundance of caution we recently noticed a number of additional dockets involving issues related to activities and projects that were undertaken and costs have already been incurred. However, we do not intend for this Technical Conference to be a vehicle to further litigate the issues in these ongoing cases, rather we intend to focus on the questions Staff raised in the Supplemental Notice for this Conference.

I'd also like to state that the view expressed by individual Commission Staff members during this Conference are those of the speaker and do not necessarily reflect the views of the Federal Energy Regulatory Commission, its Chairman, any individual Commissioner or other members of its staff, thank you, Laura, I'll turn it over to you.

MS. SWITZER: Okay, good morning. Welcome to FERC and thank you for your attendance and participation today. I'm Laura Switzer, in the Office of Energy Market Regulation. Our plan for today is to work through the questions asked in the Supplemental Notice from April 10th with a focus to develop a better understanding of the processes used for evaluation of transmission activities and

projects undertaken by the CAISO PTOs.

We will discuss the categories and types of transmission-related projects and activities -- which of these are submitted to CAISO as part of the transmission planning process and which are considered by the PTOs. We're interested in understanding how each PTO decides whether or not to submit such project and activities to CAISO.

Finally, we would like to explore whether CAISO's tariff and BPM's regarding submissions are clear, whether greater transparency is needed and if so, how that can be accomplished.

To echo Linda, we are interested in gaining a greater understanding of these concerns from a factual and practical perspective by understanding the universal projects and activities and the current process for reviewing them.

However, it is not our intention today to delve into legal arguments regarding whether the existing practices comply with the Commission's requirements, the local transmission planning, pursuant to Order 890 or any other Commission rules or regulations.

Existing records in Dockets EL17-45 and ER18-370 already includes such arguments and they may be included in any post-Technical Conference comments. Therefore, we

encourage participants to keep the fact-finding focus of this Technical Conference in mind throughout our discussions today.

We are going to allow five minutes for each of the organizations at the table to introduce themselves and make any opening remarks. From there we'd really like to start on the questions in the Supplemental Notice. There's quite a few questions and not a lot of time today so I'm going to try to keep things moving as best I can.

At noon we'll break for lunch and we'll reconvene at 1:15. We'll continue as necessary and plan to end the Conference by 4 today. During the discussion if anyone at the table would like to speak, please tap your name tent up and I will take note and call on you.

I also wanted to note that the microphones at the tables are always on in this room and I'm told they'll even pick up whispering so just be cognizant of side bar conversations. There is a phone line so they might be able to hear any conversations.

Also, for those listening on the phone I just ask that you put your phone on mute so we don't pick up any disturbances. If time allows we plan to take questions or comments from the audience twice throughout the day -- once this morning and once in the afternoon.

Let's see -- okay, again, I want to just thank

you for your participation today and we look forward to having an interesting and informative discussion. And with that we're going to start with CAISO and give them their five minutes for the opening remarks and then we'll move along the table.

But at this time I'm just going to try to keep everyone to their five minutes so you'll see me probably like around three minutes put up my hand and 5 minutes give you a wave.

I understand some parties have requested to pool their time and I'll do the same for them but at the ten minute mark and then again at the 15 minute mark, okay, any staff any -- alright, okay.

MR. PINJUV: I'll go ahead and introduce myself first. My name is Jordan Pinjuv, I'm Senior Counsel for the Company ISO, I'm working mostly in the transition client department.

MR. MILLAR: Hello there, I'm Neil Millar, Executive Director of Infrastructure Development at the CAL ISO, that's the responsibility for the transmission planning process of the ISO.

One of the -- there are probably two key issues that we're hoping to clarify today as we go through the questions. The first is that in much of the material we've seen there seems to be some confusion that the ISO's

transmission planning process only applies to regional planning and we do want to clarify through the day that our planning process includes all transmission facilities under our operational control, regional and local.

Our transmission planning process is focused on expansion and reinforcement planning. Similarly, while the utilities and the transmission owners are responsible for their maintenance activities, those maintenance activities they also hold the responsibility both for higher voltage facilities that are regional in our footprint as well as the maintenance activities on the local facilities.

So there really isn't a local planning versus regional planning demarcation the way we see it in some of the questions. The other issue that we are really wanting to clarify is that our planning process looks at identifying need for reinforcement and then picking the best solution.

It's been many years since we've had a process where projects were simply proposed and coupled together out of assessing various projects that had been submitted -- so that's another very important distinction that we seek to clarify as we go through today's questions.

So we'll look forward to helping as we go through thank you.

MR. WILLIAMS: Noman Williams, I'm the Chief Operating Officer for Gridliance West Transco. We're a

newly formed Transco and new PTO in CAISO. We've actually joined CAISO as a PTO in September 15th of 2017.

We support an open, coordinated and transparent process with transmission related maintenance and compliance activities so we're here to provide some suggestions but also to learn from other folks in the CAISO and encourage FERC to consider the suggestions to a lot of PTOs to develop their own local planning processes that provide for open and transparent processes that meet the needs of the stakeholders in the CAISO.

MR. NELSON: Good morning I'm Jeffrey Nelson, Southern California Edison. I'm the Director of FERC Rates and Market Integration Group. We also have with us Dana Cabbell who oversees much of the execution in our transmission department of the issues at hand here and counsel, Gary Chen, and Monica Donis, our representative here.

I'd like to thank you for having us here today. I'll say that in December of last year we made a filing to cover in our transmission tariff, some of the maintenance and compliance issues we do. We fondly refer to that as the TMCR -- transmission maintenance compliance review, so if I throw that acronym out, that's what I'm talking about.

One thing I want to emphasize here is a clear difference in our mind and in the tariffs and in our

controlling agreements between transmission planning -- the sort of technical analysis to expand and enhance the grid to make it bigger and better -- that's all done in the CAL ISO. The transmission planning is done in the ISO -- both local and regional.

And contrast transmission planning with -- I'll call it asset management -- we have about 9 million dollars in plant, over close to 6 billion in rate base -- under the ISO's control and to keep that machine humming along, takes considerable effort, it takes considerable activities on our behalf, but it's not expanding the grid -- this is keeping the machine going and that's what we refer to as asset management.

And while we clearly see the importance and the tariff and the applicability of transmission planning, go through the ISO's process, we took it on ourselves to try to enhance the transparency of asset management through our tariff filing, so I'd hope as we go through this day that we can keep those two distinct -- planning very formalized, very tariffed, very technical, very model based.

Asset management -- much more the nuts and bolts of keeping the grid going, sometimes far less discretion -- sometimes it's immediate response to in effect, car hits pole, things have to be done -- typical monitoring of the equipment status, maintaining it to keep it going -- so the

focus of our filing was that latter -- keeping the machine going.

With that said, we also would like to look forward to answering any questions or roles on how those two differ, how we see them and I know it's not 890 today but we do see there's different governing authorities for the transmission planning and the asset management and with that thank you.

MR. NEWLANDER: Jonathan Newlander, Senior Counsel, SDG&E.

MR. SPEER: Good morning, Will Speer, I'm the Director of Electric Engineering for San Diego Gas & Electric. Formerly I was in planning so I worked quite a bit with, you know, Milar.

The only other comments I'd like to add maybe because we share a similar view as both Neil and Jeff articulated. SDG&E has turned over all of its 69 KV to operational control of California ISO so all of our planning functions on our 69 and above are done by the California ISO. PG&E shares that and I think that is maybe a little different.

Other than that, we do share the same view, planning is done, model-based powerful planning is all done by the ISO -- it's all expansion based. The maintenance compliance activities that we run internally are really our

experts in maintenance.

We look at aging infrastructure and those types of things, thermal projects we go forward with so we look forward to a fun day, thanks.

MR. GABBARD: I'm Dave Gabbard, Senior Director of Transmission Asset Management for PG&E. With me I have Joscelyn Wong, she's my manager responsible for both the implementation of the projects within our transmission portfolio as well as a lot of the regulatory activity around rate filings within our TO and otherwise.

Just a little bit of overview of the portfolio that I oversee -- I have the transmission asset management function within PG&E which includes both the transmission planning function and the asset management functions as laid out by my counterparts.

I'm not going to take too much time because my counterparts here have eloquently expressed the state of the way that we are managing the transmission system. But I do want to echo the fact that it's very important to understand the transmission planning functions are discreet from asset management activities. We believe that there is clearly guidelines for what projects and needs are evaluated through the CAISO transmission planning process, but we also understand the need to make sure that we're investing, from an asset management standpoint, in our infrastructure PG has

over 18,000 miles of transmission line.

We also manage north of 900 different substations and there's a significant amount of aging infrastructure across that system that we need to make sure that we're making prudent investments, whether it's when those assets fail in place, or when they're nearing the end of their useful life.

And those investments take place outside of the expansion or transmission planning activities that are managed under the California ISO.

MR. THOMAS: Real quick, if you don't mind -- I appreciate that. This is Chris Thomas with FERC staff. I know that we kind of have this other table -- it probably has one mic, we might be best served to having that mic shared up and down. I know even by the tables we might have spoken softly.

We do have a transcriber and those on the phone so we could be actively minded to speak up if we get a chance, thanks.

MS. MAPES: And I'm going to start for the Complainants. My name is Katherine Mapes, I'm with the firm of Spiegel & McDiarmid and I'm here on behalf of the Northern California Power Agency and the Complainants as a group.

So we're here because each of the major PTOs does

significant transmission planning work and we do believe its planning work. We believe it involved discretion. We believe it involves more than merely asset management. It does not currently go through any public planning process.

These self-approved prove projects are on the order of many millions of dollars. For PG&E it totaled 750 million dollars in each of 2015 and 2016. For SCE it was 188 million in 2016. For STG&E the number was some 80 million in 2017.

These projects are incorporated into rates in the same way that projects that do go through the California ISO transmission planning process are incorporated in the rates. They're capitalized, they're not big fences operations and maintenance. Rate payers pay for them and they pay for a return on those projects.

This means that rate payers are paying significant amounts of money for projects that have gone through no public process whatsoever and this is a significant driver in the rate increases. The CAISO's tack has more than tripled since 2008 and PJ&E alone have seen increases of nearly 9.75% almost annually.

And the fact is that for PG&E they're not expanding their transmission system -- what they're doing is these types of projects that we're talking about today and that's a significant driver in the increases that we've

seen.

We don't know what all of the self-approved work of these PTOs are performing is, but we know that they include projects both based on sub-station and transmission line maintenance and those meant to improve outdated or failing infrastructure and to extend the lives of failing infrastructure.

This means they're classic capital work, they're not maintenance which is meant to keep projects running to the end of their natural life span. They're meant to actually increase the life span of transmission projects.

And we know that there's a lot of gray area. For instance a line remediation project that increases the capacity of that line might not go through the CAISO TPP, but it might increase the capacity of the line nevertheless.

And these are projects where significant discretion is possible. For example, a piece meal replacement of existing facilities versus a large single project that might go through a competitive solicitation process -- currently that piece meal replacement might go through no public planning process even though stakeholders might process the more comprehensive solution.

Or a utility might choose a more robust solution that's also significantly more expensive such as a breaker on a half configuration for substations when there's no call

to do that -- no configuration is appropriate in every circumstance.

Or a customer might learn that upgrades are being performed for PTO retail customers but not for wholesale customers violating Order Number 890's comparability principle.

Without a public process we simply can't know. When asked by the CPUC, each of the IOU's have pointed to their rate cases as a chance for rate payers to ask for details about the projects they perform.

This is indicative of the very lack of transparency that we're talking about today. At that point projects are decided upon and possibly even completed -- there is no possibility for information exchange and certainly no possibility for input into the planning stages of projects.

We don't see the criteria and models and assumptions underlying those projects. In short, California is lacking in the process that the Commission has held required nationwide. And this is not just a public process -- indications are that the PTO's are not doing comprehensive planning on an internal basis either and I'm going to turn it over to Traci to talk about that.

MS. BONE: Good morning, I'm Traci Bone from the California Public Utilities Commission and with me is Geneva

Looker from Whitfield Russell Associates. Thank you, so the CPUC represents PG&E, Edison and STG&E retail rate payers.

Retail rate payers pay approximately 90% of the transmission access charge. And the CPUC is very concerned about growing tack rates and balancing these costs with California's renewable energy goals. I'm here to talk about what we have learned from the -- or about the Order 890 process in California so far.

As you know we filed a complaint against Pacific Gas and Electric Company last year. We have had over a dozen voluntary settlement meetings with PG&E following our February, 2017 complaint.

Our goals in those meetings were to develop an Order 890 compliant tariff and to understand PG&E's planning processes. My focus today will be on PG&E as an example because we know more about PG&E's practices because of the 2018 rate case discovery.

And while spending on self-approved projects is significant for all of the PTOs and the hundreds of millions of dollars that you heard from Katie, PJ&E's spending on self-approved projects is of a much greater order of magnitude.

PG&E has spent more than 4.6 billion dollars on self-approved projects since 2010. We have only a few years of data showing the scope of the Edison and STG&E's

self-approval practices, thus the CPUC recently issued a data request to all three utilities to better understand and quantify the magnitude of this self-approval process from 2007 to the present and we've also asked them to forecast out five years.

This will allow us to do more apples to apples comparison of what the three PGOs are doing. We do seek uniformity in the local planning processes for all three PTOs or what they're calling maintenance processes and we would like to see something very similar to the CAISO TPP that already exists.

However, there are differences among the PTO's as we've described. There's a significant difference in how much they're spending and so we are very open to the idea of focusing on PG&E first and having individual tariffs or putting it all through the CAISO tariff -- we're still thinking through this issue.

We have some immediate challenges that we need to address if we are going to move forward with an Order 890 compliance process in California. And the first one is how do we address in-flight projects?

The second is how we transition from ad hoc planning processes that we see today to replicable processes when critical asset data is missing -- so that's going to slow us down. We also need to be able to resolve

disagreements about the need for specific projects or classes of projects.

And, given the magnitude of the customer dollars at stake, we want to see all of this happen as soon as possible, especially in the PG&E area. So in-flight projects -- we will need a going forward process -- planning process that accounts for what we've referred to as in-flight projects.

Those are projects that have already been planned and have commenced development. These challenges include drawing the line on which projects are going to be in or out of the new process and we need immediate comprehensive data regarding all of these projects in order to determine where to draw that line -- and we're going to need interim processes to determine which in-flight processes should be delayed and which should be revisited.

For example, this in-flight issue is really big. We know from PG&E's TO 19 rate case filing that was filed last year, Table 15-2, that PG&E has forecasted that it will spend 692 million dollars on capital additions this year, 510 on capital additions for next year and 256 million for 2020 capital additions -- and that's just the forecast of what it's going to spend in 20 -- in this year.

We also know that PG&E spends over 60% of its money on self-approved projects each year, thus we can

reasonably expect that just for this year PG&E will spend approximately 876 million dollars on self-approved capital additions -- so this is a huge issue.

We expect that over the next three years for what they're planning that will be over a billion dollars in self-approved projects. So we believe that these projects should receive some level of immediate scrutiny as soon as possible and PJ&E's rate cases are not the right place to be doing that.

So the implementation challenge -- how do we comply with Order 890 if the PTOs lack the processes or data resources necessary for compliance which we believe that they do? The PTOs should describe today the internal processes that they have in place, however, it is critical for us to ground truth those claims.

The TO 18 evidence shows that PJ&E could not comply with Order 890 today because PG&E does not have documented and replicable transmission planning processes in place for its own use, much less for review by others.

We suspect that SDG&E and Edison similarly do not have the data or planning processes in place today to meet Order 890 requirements. Thus, am I getting into ex parte -- are you concerned with this?

MS. KIZUKA: We notice the docket.

MS. BONE: Okay.

MS. KIZUKA: So again, we'd like our focus to be more on the technicals.

MS. BONE: Right, right, and these are facts that I think are important that we all believe are very important as we listen to what the PTOs have today because what we find is what they tell us is different than what the documentary evidence shows and that's why it's important. We can't just rely on assertions.

So healthy skepticism about what is really being done today as appropriate. In the CPUC's gas transmission experience we found that while PG&E had procedures in place it often did not follow them. And we also found that while PG&E executives claimed that the procedures were being followed, the evidence showed otherwise -- so it's important to keep these things in mind.

Also, PG&E has started to develop 2017 strategy documents and this is what the evidence shows in TO 18 however, nearly every strategy document that you looked it, it's a PowerPoint presentation it's not very robust and so our concern is that there aren't really even real transmission planning processes in place today for these maintenance projects.

I'm going to skip ahead so that Dave has more time. Let's see, okay, I'm going to turn it over to Dave.

MR. DOCKHAM: Well good morning, thank you for

having us here today. My name is Dave Dockham, I'm with the Northern California Power Agency, I'm Assistant General Manager for Power Management there.

I've handed out a PowerPoint presentation if you want to follow along and just get into it. What you've heard from all of the speakers so far today is that there are two processes, they're governed by a series of documents that relate to system expansion versus other transmission related work.

As you can see on the left-hand path we have the tariff, we have business practice manual for the planning process -- that yields a set of unified planning assumptions that dictate the studies that are going to take place each year as part of the CAL ISO's plan. It ultimately results in the production of a formal transmission plan.

All of the other transmission related work follows a separate path and that's the path on the right and that's governed by the transmission control agreement or specifically Appendix C of the CAL ISO's maintenance standards and a set of maintenance procedures.

The next slide -- I think what you've also heard today is that there's a huge separation between those two processes. CAL ISO handles everything on that left-hand path and the investor and utilities are largely responsible for everything down that right-hand path and never the two

shall meet.

Coming out of this year's process, and I think we're generally pretty satisfied with the CAL ISO transmission planning process. You know you can critique any one project outcome and we've done so this year, but in general that process has improved year over year. They do an incredible amount of study, lots of involvement and the projects coming out of the back end of that are pretty well understood.

As you can see this year -- that process resulted in the elimination of 18 projects and a revision of a number more and resulted in a total expenditure of 271 million saving close to 2.6 billion into the future.

In contrast, we don't have an equivalent public process on the maintenance side path. What we see generally comes out in the TO tariff filings. In many instances when it's too late to do anything about the projects that we ultimately see there.

And just for comparison when you look at this year's most recent documents -- you compare the CAL ISO transmission plant that was released in March -- PG&E's TO tariff filing that was published -- it was filed last year in June, CAL ISO total projects 271 million, PJE&E's self-approved project 857 million, when you back out the projects that go through the CAL ISO and the work requested

by others, so nearly a three times greater set of costs for the self-approved projects that are running throughout without any public participation to those projects that are going through the CAL ISO transmission planning process.

So we think the solution is pretty straight-forward. We really need to reform the transmission planning process -- that path on the right side of the document that I handed out. And I use the term transmission maintenance process and I'm hopeful that as part of the discussions today, we can focus in on three terms because they can be contradictory and confusing at the same time.

So we have the CAL ISO maintenance standards, big S and little s and it's used interchangeably throughout the document and it's important because it distinguishes different responsibilities.

We have maintenance practices which are confidential and we have maintenance procedures which are merely guidelines. As part of the discussion today we're really hoping we can find out why do you need to be confidential and why they're only guidelines.

And I'm on slide 8 but when you look at the maintenance practices themselves, they seem to be pretty robust. As Traci mentioned when you drill down into those maintenance practices, what you find isn't nearly as robust or coherent or complete as the standards would lead you to

believe.

And so I'll just take one example 5.2.1 transmission line circuit maintenance where it says, "As may be appropriate for the transmission line circuits on the CAL ISO's operational control." Replace that with, "As may be appropriate for the specific transmission line circuits under the CAL ISO's control, each PTO's confidential maintenance practices, shall describe the maintenance activities for the various attributes listed below.

Similarly when we get into the maintenance practices, we suggest that we take a look at Section 2.1 of the -- they expect to set out a scope, there's a number of objectives listed there and amongst the objectives are achieving high-quality and reliable grid.

The last objective is the achievement of the aforementioned the subjective is defined that a minimum reasonable total cost for maintenance with the intent of minimizing customer impacts -- that simply asks how you validate that? How do you confirm that that's actually happening with confidential or guidelines as the basis for the projects that are being done?

So as you've heard we believe modifying the other transmission work so that the process follows more closely with the CAL ISO's transmission planning process is the solution. We're looking forward to the discussion today. I

think you've asked some great questions and we're looking forward to participating in the discussions associated, thanks.

MR. GRIESS: Good morning I'm Brian Griess with the Transmission Agency of Northern California. I'm TANC's General Manager. I'll keep mine pretty short. We did a handout that's got some of the background on TANC and what TANC's objectives are, but I'd like to echo some of the concerns that have already been raised.

We just are very concerned with the lack of transparency on the transmission planning process for the local transmission projects. I know that there's a question of whether it's maintenance or whether it's planning -- the fact of the matter its capital additional that are affecting the overall California ISO's tack and they've become very costly over the past several years.

There's no opportunity for the stakeholders to look at these capital additions that are compared being self-approved. When it comes to the TO tariffs it's too late, they are already in project, in service or they're being constructed.

So we echo the request to come up with some type of management -- some type of transparency where we can have a unified approach to looking at all of these self-approved projects that eventually roll into the ISO's tack, because

without that today there's no checks and balances, keep it short.

MS. SWITZER: Thank you, alright with that we're just going to dive right into the questions. A number of them have questions today -- the first one please define and describe what constitutes transmission related maintenance and compliance activities facilities.

Please provide specific examples and an explanation regarding how it is determined that such examples fall into the categories of transmission related maintenance and compliance and how each CAISO PTO identifies these needs for these maintenance and compliance activities and decide which activities to undertake. And this one I think we'll begin -- we'll begin with Jeff Nelson but on the PTOs, but again feel free to tip up your tent card if you'd like to speak.

MR. NELSON: So Dana's the expert on this but I'll just sort of frame certain policy big picture. To the extent that we anticipate funding -- to the extent that we anticipate an activity is actually going to expand the capability of the ISO's grid.

Those activities make their way into the transmission planning process. To the extent that we're looking at activities as I framed before, maintaining, keeping the grid going, there may be capital spending --

sometimes there's capital replacement that has to happen to keep the machine running, but it's not changing the topology of the grid, it's not changing the capability of the grid, it's keeping the machine as it is, going.

Those will fall into the TMCR type processes and I'll turn it over to Dana from there but there's a whole host of standards and processes we follow internally to make those decisions.

MS. CABBELL: Thank you Jeff. And just to level set also, the Southern California Edison that is under the ISO control is our 220 and 500. It goes down to basically the high side of the 220 66 substations but does include the 220 circuit breakers and we do have maybe about 5% that is 115 KV, that is under ISO control, but it is quite different than what is under control of the ISO for San Diego and PG&E so it is a smaller group of assets that are under ISO control.

So as we laid out in the TMCR we were categorizing these type of asset management projects that we were putting forward as within our stakeholder process as we outlined in the TMCR filing.

And so we were looking at compliance projects, infrastructure replacements, some projects that offer operation support and also some work that is contractually required. When we talk about compliance -- and I should

again say whenever we're doing any type of these asset management projects, we're not looking to expand the grid at all.

We're just replacing the equipment like for like. On these compliance projects that I spoke about, what the big expense right now that we're -- we're going forward with is efficient line rating deviation -- essentially bringing up the ground plants, improving the ground plants of our transmission line.

And this is to be able to meet the CPUC policy. And when we're doing that we're not actually increasing the capacity of that particular transmission line, we are just making it to the actual rating that's within the ISO registry. We're not increasing the opacity.

Now, as Jeff mentioned, there was one project that we were remediating the ground clearance that we saw if we spend extra capital, it actually met a need that the ISO identified in the transmission planning project.

So what we did was we evaluated spending some extra capital on this asset management project and with that incremental increase of capital, we were able to meet an ISO need. So what we did -- we took that incremental piece of work through the ISO process because that did expand the grid.

So we do, we do really distinguish between pure

asset management and the transmission planning which expands and enhances the grid. The infrastructure replacement projects that we look at typically are circuit breakers, transformers -- and the way we identify the need for that we take them through a health maintenance tool.

We look at the age, we look at the criticality of the piece of equipment. We -- it's done by visual inspection. It's also done by some engineering predictive analysis so there is some techniques to understand.

Okay, how likely is this piece of equipment going to fail just based on these other parameters that I outlined? So it is a very robust process that we go through to identify which circuit breakers are we going to need to replace and then we also go through a way to try to prioritize that work.

So, you know, trying to replace this aging infrastructure which is, you know, quite a bit on the system, we can't do it all at once obviously. We spend about 200 million a year on these types of work -- on this type of work.

But we do have a very predictive engineering analysis for circuit breakers and transformers, and then for the transmission line remediation we actually did some technical -- what they call LIDAR -- kind of measuring what the ground clearance is.

And we had over 1,000 discrepancies in the line rating so we're going through that and we have until 2025 to remediate that.

MS. SWITZER: Question?

MS. CABBELL: Sure.

MS. SWITZER: The example you gave where it was going to expand the capacity of the line say you kicked it over to CAISO to study, but that's a decision that Edison would make though, correct? You decide if you want to do that and then have CAISO study it? Can you just explain that a little bit?

MS. CABBELL: It was our -- there was a reliability issue that the ISO identified in the transmission planning process up in our Bid Creek system, it's a 230 system that's up in the Bakersfield area that helps deliver our hydro generation for my Bid Creek plants. They identified a reliability issue when we have low hydro and some contingencies in that area.

So that had been in their transmission plan as an issue and we had identified that okay, we have this maintenance project that if we add some work at some additional towers, we can actually increase the ampacity of the line and so we took that incremental into the ISO process to meet that need that they identified.

MR. NELSON: So if I could say -- we suggested it

to the ISO. We didn't approve it, we didn't unilaterally do it. We suggested it based on a no need and it was up to the ISO to give a go/no-go to the transmission planning process.

MS. CABBELL: Absolutely, yes.

MR. THOMAS: A couple of follow-ups to that if you don't mind. As I heard it you talked about the incremental nature or incremental piece of that. When you offered that, did it have a change in the character of the total project from the maintenance side?

MS. CABBELL: No, it did -- it was the same work that -- we actually did some additional work at the piler's to bring the rating up or bring the line up further and increase the ampacity of the line itself. So the core maintenance work did not change.

We just added some additional work at some of the towers to be able to meet this need that the ISO identified.

MR. THOMAS: And so in that regard then I wonder if CAISO can possibly answer on this one -- with that is it -- would it have been reasonable maybe to consider the entirety of the maintenance project including the addition as far as purposes of the transmission planning process?

MR. WILLIAMS: And so let me just back up one detail and I just want to reinforce the need for something in that area was identified through our routine process of testing the needs on the system.

We put that out every year in the mid-August timeframe. We solicit suggestions from everyone -- not just the utilities on how we could potentially meet those needs. Edison did identify the need to do their capital maintenance with this maintenance activity that was the bulk of the project and proposed the incremental adjustment -- the incremental expense as the way to address our reliability need in the area.

Now in doing that, other stakeholders had suggested some other massive transmission line substation Greenfield projects. We did clarify that the maintenance responsibility -- Edison had a maintenance responsibility to take care of their transmission line, that the low clearance had to be addressed.

So we focused on the incremental cost and the benefit we would get from that incremental cost and that's what the ISO board approved. Incremental -- recognizing that Edison had to address their safety and rating issue separately.

MR. THOMAS: Thanks, Can I -- and I'll just ask for the purpose of the community. We've moved the microphone down by you guys a little bit, Neil if that's alright. Thank you, I appreciate that.

MS. SWITZER: And one more -- you mentioned the health maintenance tool. I was just wondering if that was

publicly available?

MS. CABBELL: We've never had the reason to make it public available. I think it's described in our PUC rate case proceedings. I don't see why it couldn't be publicly available, I'd have to go back in and understand all the details of what's in there, but that's something that clearly we'll take back and through our TMCR as we go into our stakeholder process, that's the kind of information that we'd be sharing with the stakeholders.

We've never had to do this, we've never thought of doing that but now with the TMCR that's what we're proposing and so clearly we'd be putting out this kind of information.

MR. NELSON: We have answered questions about that in our rate cases. You heard a theme about there's not transparency. In our rate case we put a draft out four and a half months plus before we filed. We go through a significant, sort of data request process and we have gotten questions about those types of activities through that process currently.

The TMCR -- our rate case basically looks forward a year. The TMCR will look forward five years so if we saw something in a five year horizon we'd -- I'm struggling with the correct word here -- describe what was happening and explain what was going on with the TMCR process and then

they'd have real drill down in our rate case.

MS. TEETER: If I could ask a follow-up question this is Valerie Teeter with FERC staff. So it's helpful with the examples that you have provided of what's kind of taken care of through what you're returning as an asset management process.

I guess what I'm trying to understand is, you know, you've given us some concrete examples that a lot of the infrastructure replacement is, you know, individual circuit breakers, transformers -- I'm trying to get a feel though for how much of this process is focused on kind of looking at these small components of the system versus aging infrastructure in a larger sense.

You know, are you looking at entire replacements of lines, reconductorings, are you looking at replacing existing sub-stations in kind, and when you do those replacements are you really replacing it at the exact same specifications it was initially designed for or are you considering as part of this aging infrastructure initiative as part of your asset management, whether there are improvements that you could make to these facilities that would better meet your needs as they've evolved since they were first built and is that being done through these asset management processes -- does that make sense?

MS. CABBELL: Yes, it's a lot but --

MS. TEETER: Sorry.

MS. CABBELL: I was trying to, you know, listen very closely. When we're -- let me see, hopefully I answered your question so please follow-up if I missed something. When we're looking at our aging infrastructure on the grid, we actually are looking at components.

We're not looking at entire substations or transmission lines, you know, for replacement. If a transmission line needs to be conductored that would typically mean that there was an identification of a need for the transmission planning process at the ISO, because when you re-conduct, you're expanding the grid, you're not just replacing like for like.

Now on some of our remediation that we're doing we are -- could be putting into a conductor that maybe ultimately, just like the example we've been talking about, maybe you can do some other work that you can improve upon the capacity that you're adding, but we are just adding the facilities like for like capacity.

We're not adding anymore because we don't -- there wasn't a need identified so we're not going to be putting in extra capacity unless a need is identified in the ISO planning process and we take that through that process.

MS. FARINELLA: I guess I, this is where I have one follow-up, so it sounds like you're defining maintenance

as replacing like for like and expanding -- I'm still not sure what the definition of that is yet, but I heard Valerie's objection more as when you're looking in the maintenance category of like for like, do you look beyond that?

Do you consider something more than that? I didn't hear that part.

MS. CABBELL: No we don't. We look at just replacing that circuit breaker -- replacing that transformer. We're not looking to maybe add a larger transformer because maybe in the future we think there might be a need for that.

MS. FARINELLA: Is that typical for TO planning that you don't look beyond the replacement of like for like?

MS. CABBELL: This is not -- this is not planning. That's a distinct -- that's where we're trying to keep it -- this is for asset management, this is for maintenance. We do have a transmission planning group that works closely with the ISO in the transmission planning process where they do all the technical studies, the power flow stability studies of the grid to determine do we see some future needs for actually expanding or adding capacity to the grid to meet a reliability standard issue -- a NERC reliability standard issue which is identified within the ISO process.

These are just -- this is just maintenance that is happening on the components of the grid.

MR. NELSON: If I could follow that -- in the planning side of the organization they're constantly looking at how things are changing, what we think is happening in our system and we're frequently making proposals to the ISO for a very open process and transition planning process.

Everyone's welcome to put ideas, raise concerns, put things in front of the ISO -- we do that frequently, but we don't have unilateral decision making. Those suggestions could filter through the processes the ISO has and they ultimately decide go/no go or what the requirements are and who ultimately will be doing those.

Sometimes it's Order 1000, sometimes it's not -- it just depends on the specifics.

MS. SWITZER: Let's go to the Complainants and then CPUC and then --

MR. THOMAS: I wonder if we do it real quick. I know Dave you had your tent up first. I think some of these questions -- I'd be remiss if we didn't hear from all three PTOs to ensure either one -- continuity or there's a difference so we can ensure the validation of these questions.

And then we'll go and it looks like Miss Looker had her tent card up, that way we can go right down that

line based upon all of your responses to question one -- would that be good? Whoever would like to go first.

MR. SPEER: We share a similar process with the aging infrastructure replacement. One thing I would like to add is when we look -- you talk like for like in one system -- we're looking at those components and we're looking across our whole system and that's how we determine and which ones need replacement right, based on age, based on condition.

So when we look at transformers we look at all of our transformers. We look at breakers, we look at all of our breakers and determining which has the highest risk for failure and we'll replace those first.

So it is both that asset management piece. It's not a planning function, it's more asset management. A couple of other things on aging infrastructure that we do and I would imagine they do too is on substation structures, and we have to meet high seismic requirements in California so we're going to look at some of our structural steel, our disconnects and make sure that those meet the new seismic requirements.

So when we look we could -- actually Janene, could look at and we found a few -- we found a transformer and a couple of breakers and we know the structures are not -- they're not meeting current standards so we might -- that

could be an asset management type replacement.

So we wouldn't be upgrading the system but we would be replacing all those things at one time because you're not going in one doing a transformer, going in two years later, doing a breaker then doing the steel -- so that's where they might come together.

Other types of projects -- fire hardening, I think everybody's familiar with the risk we face in California with the threat of fires so a lot of the work we do for San Diego Gas & Electric is the wood to steel pole change-outs, increasing conductor space kind of our East County, our high fire threat area.

That's a big part of our asset management risk reduction. There's really fire hardening -- I lied. So those don't necessarily go through the ISO, they're not to change the topology of the grid -- they're really to strengthen our lines for fire threat.

A couple of other things too -- there's inspection and maintenance driven so we have wood pole intrusive inspections so we go out and check the entire unit pole. If it doesn't meet a certain criteria we're going to change those poles out and that's just based on the structural integrity of the pole.

And I think one other item is probably security -- to both cyber and substation security projects. So we

look -- we have a copy, we have our own security internal security department that looks at, you know, what's the highest risk from a security perspective of those substations -- removable poles, you know, new fencing, revolves around transfers and things like that.

So those are some of the other projects that are kind of outside the planning -- they're more asset management, how do we take care of our assets, how do we insure, you know, we don't have any failures, and I think that's it for adding.

MR. GABBARD: Excellent. So I know this first question is just about the different types of work. A lot of the different types of work have already been called out so I don't need to revisit that. But I do want to highlight that we've been talking about this in this forum today as if there's a certain type of work that goes to the California ISO and a certain type of work that doesn't.

And what I'd like to change the thinking a little bit on is that there are categories of types of work. There are proactive asset replacements, there are reactive asset replacement on emergency, there are capacity driven projects, customer driven projects, et cetera.

Those categorizations are based on the need -- ultimately the determination on whether or not the evaluation of a potential project goes through the CAISO

planning process or not, is based on a set criteria.

It's whether or not the modifications to the transmission grid will add a new element, will change the topography of the grid, will impact the power flow of the transmission system. There's also consideration that the transmission planning process or the CAISO planning process isn't just transmission planning, it's also interconnection planning so whether or not we're interconnecting or building deliverability for a generator would dictate whether or not it would be evaluated under the generation interconnection and deliverability allocation procedures -- that's also a CAISO planning process.

So when we talk about different categorizations of project types, that just defines the way we think about the work, you know, really the engineering mindset in identifying the need, whether or not it goes under CAISO review is based on whether or not it's expanding the transmission system or impacting the overall power flow of the transmission grid.

That comes into play when we think about some of these questions that have come up and we've even heard some great examples that we've experienced ourselves. We're going out -- we have the need that NERC alert said we need to go through and evaluate the as-built condition of all of our transmission infrastructure and make sure that the

clearance to ground is in compliance with the general order under CPUC regulations in order to be able to maintain the certain current capacity.

In order to mitigate some of those discrepancies we've also had to raise the towers. I wouldn't say as part of either the proactive replacement of assets or the mitigation of some of those compliance discrepancies we looked to do transmission planning but as prudent utilities we are always looking for opportunistic opportunities to poll our various engineer analysis across the different processes together.

And as the opportunity arose where we were doing -- where Edison was doing a NERC compliance project and saw a need identified through the CAISO transmission planning process, they presented that through that process as a potential opportunity to increase scope and more cost effectively mitigate two needs.

We have some similar things where we will replace like for like on asset replacements but we also know the topology of our system. We are engrained, it's a CAISO transmission planning process but our transmission planners are hand in hand with the CAISO transmission planners -- so we know the needs on our system, 10 plus years out and we understand those needs and as asset management related activities are identified that may present an opportunity to

propose a project in the transmission planning process that can achieve some efficiencies, we will do that.

So there are those synergies on occasion. They're very few and far between. We look for them, but at the end of the day the peer asset management project is replacing like for like, existing infrastructure that is confirmed needed by the grid. It was put in tens and tens of years ago and it's needed to maintain safe reliable operation of the grid.

And as prudent transmission owners we have an obligation to make sure that we're investing that infrastructure to maintain the safe, reliable operation of our system.

MR. THOMAS: I may have a question, I want to remind everyone to do is when you do have a question, whether it's from the audience or stand-up please identify who you are, who you're with so we can assure the transcriber has all of that.

MS. LOOKER: Thank you, I'm Geneva Looker. I am with Whitfield Russell Associates. I am consultant to the CPUC and I have been involved in some of the PG&E cases and I'm now starting to be involved in some of the Edison cases.

And when you asked the question about the like for -- you know, do you replace in kind -- and I have to say

that based upon what we have been able to review for PG&E's internal planning process, that is often not what is happening. They are making upgrades to the system that granted do not increase the capacity of the system but they are upgrades.

They are changing the breaker configuration to something that they consider more reliable. They are adding modular protection components, they are adding a lot of scata equipment -- this is all important stuff.

We don't -- we agree that some of this is important, however it is being done without the ability of the stakeholders to have any ability to review, participate, say hey, do you need to do this right now? Do you need to put this incredible amount of dollars right now or can it be spread out or can you replace in kind rather than upgrading to something that is bigger and better?

You'll see that in PG&E's filings they have a whole category of projects that they list as reliability.

OFF MICROPHONE UNIDENTIFIED SPEAKER: Interruption.

MS. LOOKER: So just to reiterate, you know that they have a whole component of hundreds of millions of dollars every year that they're putting into something that they're calling reliability but it's not going through the transmission planning process. It is not transparent. We

don't have a way to look at it and review and see it and that is just what I'd like to point out.

MS. TEETER: This is, we have someone else -- if I can follow-up, this is Valerie Teeter again from FERC staff. I'm trying to kind of get a better sense of where the line lies between what we're planning here at asset management versus expansion.

So if I can clarify, is it that expansion is literally -- let me go back to my notes here -- I think PG&E mentioned it will go through the CAISO process if it adds a new element to the transmission system and if it affects the topology of the CAISO grid, if it impacts power flows on the CAISO grid -- is that supposed to be the line between these two and if so, where is that delineated?

Is it something that's in CAISO's tariff, is it something that is just kind of the standard practice in CAISO, is it in a business practice manual? I guess I'm trying to get a sense of where the line really is and if it's really just capacity upgrades versus changes in equipment configuration that may not necessarily change the topology of the system but there are bells and whistles that may be going on these replacement staging infrastructure.

MR. MILLAR: It's Neil Miller, so maybe I could take the first shot and then see if it's anything bad. Our

view is that the delineation is really based on why -- so the same upgrade could go through either process depending on why it was found to be needed.

Our planning process sets out a very specific set of issues that we look out in a reliable system to achieve policy direction to provide economic benefits to consumers and so forth. So the criteria we're looking at for why we would need to extend or reinforce the system is set up in our tariff as well as in our business practice manuals.

So in that work we had prior needs, we look for potential solutions including suggestions from stakeholders. Now just picking on an example like some of these substation modifications -- if we identify that an existing breaker configuration creates an unreliable system that isn't using our criteria, we would identify that and the utility like proposed to reconfigure that substation or there might be other alternatives that we would look at, and we would pick one, get it approved and move forward.

Now if we did not have a reliability need to make that modification, the transmission owner determined that they had aging facilities, they needed to reconfigure and the current configuration wasn't offerable, that they didn't have adequate access to get in with maintenance equipment and so forth, and they chose to propose to reconfigure the substation purely for maintenance purposes, that would be

their responsibility to defend that providing a configuration we could accept. It would not go through the ISO planning process.

So the big difference here is why -- how is the need for the project identified? Our process identifies the need for enhancements and reinforcements. I keep having to mention reinforcement because a few years ago, I had a load growth -- an expansion with a common. Now, with changes on the generation fleet there are times when we're needing to expand the transmission system to address retirement generation and so forth, so that to me is a reinforcement type project, but it's still called for through our constant funding requirements. Sorry, that was a bit of a side.

MS. TEETER: That's okay.

MR. MILLAR: The big issue though is really that what is driving the need for the projects determines how it's handled in the different processes.

MS. TEETER: Well if I can just recap very quickly and then we'll move on. What you're saying here is that it isn't necessarily whether or not a particular activity expands the transmission system, changes the topology, it's more about there are subtle criteria in the CAISO tariff, and business practice manuals that outline the needs that CAISO will plan for.

To the extent a project meets one of those needs

or an activity meets one of those needs, it is going to go through the CAISO process, CAISO is the administrator of that process and will make the determination as to what solution best fits, best meets the particular need.

If a project does not meet a CAISO need, that's something that is -- would be considered more asset management, go through a PTO specific internal process.

MR. MILLAR: Yes, that's right and then through the years -- as mentioned, my finding team does coordinate with the utilities to insure that we are moving on a path towards perhaps finding solutions that affect a certain area. We do need to coordinate to make sure that it's consistent with we're not going to create a conflict with any other metering activities that are going on in the area.

MS. SWITZER: Can I ask a quick question? So CPUC rule about raising lines. If that's a state liability rule, how come that's not something that CAISO -- why is that a maintenance left to the PTOs and not something CAISO approves in the plan?

MR. MILLAR: Actually I'll defer to Dana after because she is the expert in these areas, but the fundamental gist of it is we do address policy requirements but we do not address flat out safety -- maintenance safety issues. And the general order I would characterize around the necessary clearance for safety is actually a

transmission owner's responsibility.

MS. SWITZER: Okay, the CPUC's policy would go through CAISO but the safety or maintenance that's --

MS. CABBELL: Yeah, this particular one that we're talking GO 95 is purely related to safety.

MS. SWITZER: Who decides -- wait, who decides what is included in the plan and that is at CAISO? You would look at that rule and say this doesn't meet our criteria?

MR. MILLAR: There's actually -- there's the first line and then I'll say the second line of defense in how they handle that. When it comes to an issue first we turn to our tariff that lays out all of the specific sets of circumstances that we're expected to address as part of our expansion or reinforcement planning.

We also share as part of our stakeholder process in developing our annual study plan, also have an open call for policy issues that stakeholders feel the ISO should address as policy issues inside our transmission planning process.

And those to this point, are focused almost exclusively on accommodating renewable generation. I haven't had anyone actually suggest in that process that as a matter of policy we should be looking at safety issues. Our view of the safety issues specifically is though that it

is clearly laid out as a transmission owner responsibility under our transmission control agreement.

So we vote with the transmission owners. So we believe the safety issues have already been debated and those responsibilities are clear, but for anything new that emerged, we actually have a process that allows stakeholders to raise any possible policy issue that they feel should be incorporated in the transmission planning process and our tariff actually calls for us to provide a written response how we chose to move forward or not with that policy effort.

MR. THOMAS: Mr. Dockham, you have a question?

MR. DOCKHAM: Yes thank you, I just want to follow-up on a couple of things I've heard and maybe get a response to it.

When you talk about the CAL ISO's process and the planning versus the maintenance, one of the things we've come to understand through our discussions with PG&E -- I think it's included in their filing as well -- that they have a set of projects that are related to substation replacement activity.

So for example, they have old substations with a double bus, single breaker configuration and they have identified in their processes that a best practices -- changing that out to a breaker a half scheme so it's not a like for like type of replacement -- it is an enhancement.

The problem that we see and that we've complained about is we can't tell when and why they use a breaker and a half scheme as a replacement versus just increased sectionalizing and we sought that play out in the CAL ISO planning process this year where one of our members was subjected to increased sectionalizing as opposed to this more robust and best practice breaker and a half scheme.

So what we'd like to understand is how are these decisions made -- why do they seem to take place within the IOU service territory as opposed to where the municipal customers are connected and this lack of transparency into the exact practices that are used to make these decisions are not making things any easier for us to figure it out.

MS. TEETER: This is Valerie Teeter again from FERC staff, if I could ask a clarifying question. I just want to make sure that I'm understanding. So I think a point that you're raising is that it's not just what's going through the CAISO process and what's not, but you're seeing what you believe to be a difference in the practices that are being used internal to the PTOs retail customers versus what's being used at -- in the planning for wholesale customers?

MR. DOCKHAM: Yes, yes, and you know, I'll take it one step further. In terms of the performance criteria that are identified in the CAL ISO's maintenance standards,

you know, the availability, reliability, impact on consumers are identified as a threshold measure there.

When you look at the effect on municipals even though there are thousands of customers behind the meter that is serving as the take-out point for municipal load, you count it as one customer.

So when you look at safety, KD, metrics, it counts as one customer in all of those metrics as opposed to let's just say the 30,000 customers that live behind that meter.

MS. TEETER: And those are added metrics, correct?

MR. DOCKHAM: Correct.

MS. TEETER: Okay.

MR. SPEER: Well maybe, Will Speer, SDG&E, maybe I can address a little bit of how -- at least for SDG&E how sometimes we change configuration. A lot of it is based on base, substation requirements. So you have a limited area within your fence. That could be a driver on why you would put in break and a half, double bus, whatever you do.

I agree a break and a half is the preferred method but a lot of times we're limited on that. And you're also limited on actually taking outages to do the rebuild, so that's a huge constraint.

So if you're looking at a 230 cable substation

with four lines going in -- multiple transformers, you need to consider -- you can't just take it up and rebuild it next week. You're building within the existing site. So a lot of our configurations, we do work with the ISO on that, talk about out of sequencing, what's the ideal solution line at the end and they'll be aware because that is changing topology but a lot of it is just driven by the constraints of the site and the outages required to do the actual rebuild.

But that is coordinated with the ISO at least for SDG&E.

MS. SWITZER: Okay, I think we've covered question 2 pretty well, as well as 3. Going to question 3 -- we talked a little bit about this but just really if you could explain again the differentiation between CAISO's planning process and what your planning -- or not planning, what the maintenance products.

Specifically, what factors are considered, we have your cost voltage level of rating -- does any of that factor into that like -- that one example Edison gave with the incremental project meeting a need or could we just expand on that a little?

MS. CABBELL: We've done a lot of the talking already related to this question also but to expand a little bit more on when we're going in looking at our assets and

doing our asset analysis to determine does that equipment need to be changed out because of age and intimate failure possibility as to the statistical work that's done about that.

Again, since that is just looking at changing like for like. Maybe they're -- and you have to remember our system is a little bit different. We don't go in and change a lot of our 66 side of substations. We do rebuild because of some concerns with RACS but that does not go into the ISO, that does not go into TAC, that's for us, that's our local so.

So really again the distinction is the work that we're doing adding additional enhancements and capacity to the ISO and is it meeting an identified ISO need that they put forward in their transmission plan?

MS. SWITZER: So it would have to be both -- meeting a need and an upgrade?

MS. CABBELL: Yes.

MR. NELSON: If I could and this is a little out of my scope but I want to try and contrast a little bit with PJM what we do. It is my understanding in PJM they have certain planning processes, look at reliability criteria and that's sort of the bulk of their planning process and then they defer a lot of the local transmission to the individual utilities to kind of, you know, enough broad brush, let them

do what they want to do as long as it doesn't mess up their reliability.

I think we're very different in our ISO. They do all voltage levels as long as it's within the ISO. There's not a bright line that says hey, if it's below "X" utilities handle it, they do all voltage levels. They don't defer to the utilities to kind of do things that change grid topology. That -- there may be exceptions to the rule but that goes through the planning process.

And it's not just for reliability criteria, just for emphasis -- that's only one category of project that will go through. They also do economic projects where if they just think it's going to save the customers money by building a line, that has to go through the transmission planning process.

If we think a line will save customers money and we should built it, we take it to the ISO's planning process and try to convince them that it's a good idea. They also do it, like Neil was saying, for policy type lines. The PUC decides if there is a renewable rich area for folio and they want access -- transmission access, there's coordination with other state entities that goes in the planning process and if that bubbles through the ISO will design a new policy line and again, whoever builds that is going to be unique to the specifics of that situation and maybe Order 1000, it may

not.

But there's not these sort of bright lines that I sort of see different in PJM where they do defer a lot to the utilities. I don't see that in our case. It's all in the ISO in those major things and not just for reliability, for policy.

MS. TEETER: So this is Valerie Teeter again, FERC staff, just if I could ask a follow-up question there. I guess it would be helpful to me to understand so for example for internal utility planning standards that aren't you know, they're not NERC standards, they're not NERC reliability standards but they're -- you know, in CAISO it is different than PJM, your single state.

You know there is a single set of state standards, but if you have utility kind of specific standards, internal standards to, you know, that may be necessary to protect your equipment or just kind of the differences in how the utilities have typically operated their system, who plans to meet those standards?

Are those something that you provide to CAISO for consideration to their process or is that something that's considered through asset management?

MR. SPEER: So I think there's probably a distinction there. I think the ISO plans for everything that, you know, they're responsible for. And it goes back

to kind of the distinction asset management planning we've been trying to draw the lines.

So that is responsible for any of the planning standards, those are clearly defined. There's, you know, the NERC standards, WEC standards and the CAL ISO planning standards. For SDG&E we don't have additional standards.

MS. TEETER: Okay.

MR. SPEER: But we -- those are the standards for planning the transmission system. Asset management we do have guidelines around asset management, you know, when equipment reaches a certain threshold life, you know, the condition of the equipment, we'll have standards around that.

So I think that's probably the distinction. It's not planning standard, it's really asset management standards. We have protection standards also, things like that but anything planning is all governed by the ISO and really NERC sets the bar and then.

MS. TEETER: So you're not -- you don't have kind of internal sorry, internal utility standards for how the system operates or kind of the performance you expect out of your system that you would give to CAISO to kind of put in their models. Is that something that to the extent you have those protection standards et cetera, those are a piece of the asset management program, is that fair?

MS. CABBELL: Yeah.

MR. MILLAR: Yes and I think there's one clarification I can add there. There are cases where each utility may feel that because of their equipment there is some specific issue that needs to be addressed a bit differently within the transmission planning and those get incorporated into the ISO planning standards and the one issue I'm thinking of is not everyone has the same ability to accept certain high voltages.

The voltage requirements -- the operating voltage requirement for each utility can differ based on their particular equipment. So some of these differences if they work, they're built into our planning standards and that's what we're using and we're asking our board to approve a project which then obligates someone to actually go build that project.

So that is an important clarification. So those are built in. Now there are actual maintenance requirements -- we may have disability of those but that's not an issue that the ISO passes judgment on -- on whether or not someone should take a risk around prolonging a piece of equipment -- we're not making that judgment call, we're not accepting the risk or liability for making that decision, that's the utility's decision.

We do expect them to do their maintenance and we

do have a separate program around ensuring utility maintenance is being done, but that's separate from planning discussions.

MR. THOMAS: This is Chris Thomas with FERC staff. Just to follow-up on Valerie's question because I thought it started to maybe hit the hub of a lot of what we've seen in both the cases and what's in front of us today is -- you mentioned that you have a set of criteria by which you'll do your maintenance and so forth.

And I wonder if each of the three PTOs is that criteria known and measureable to the PTO, that is where the customers or whatever would see those or are they not necessarily made known and measureable because of specific reasons. I'd be interested in knowing that answer and are they consistent?

For example, are we held -- are you all held to a certain set of guidelines on a transmission system or system upgrades repairs and maintenance. For example, if I went and redid my home, certain code has changed over time, I'd have to do various things. Do those things have applicably or code that's outside of the scope of our regulatory theme have a play on what you guys do in your maintenance practices?

I know there's kind of three questions there.

MR. SPEER: Well I'd say one example there is

industry best practices right and we all attend conferences or stuff that goes on throughout the year around those things. I would imagine our processes are a little different. We have different types of equipment, different age of our equipment. So I don't think we're going to share those things but we all try and meet industry standards right -- best practices.

There's a lot of work around that. We work with manufacturers too. We all pretty much buy the same equipment, there's big suppliers seen as ABB types of things, so they have recommendations around that.

So I would imagine we're pretty consistent in that.

That's the way we do our --

MS. FARINELLA: Do you have a view on the first part of his question about --

MR. SPEER: What for share -- yeah I don't believe -- for us -- I don't believe we've shared it yet. That's something we could take back and talk about. I just -- there hasn't been a need at this point to share that. So we do share at industry events, you know, we have speakers from SDG&E go and present how we do our maintenance practices, what our best practices -- so it's kind of a, you know, that's the environment where a lot of that gets discussed is what's the best practices around maintenance

and do we participate there.

But we don't have a file plan publically on those practices.

MS. CABBELL: Yeah this is Dana Cabbell, I echo what Will just said for Edison also. I mean we -- yeah, we might have different type of data and technique but we do go to the different forums for best practices for operations.

MR. NELSON: I'll note though that in again -- in rate case scenarios we've fielded request questions about how are you doing it and I believe what you're hearing here is that there's evolving processes and there's unique situations but we have answered the questions when asked on that, you know, it may not have been fully satisfactory to the person asking it, but we have attempted to answer those questions.

MR. GABBARD: Yeah I would add that in general there are compliance obligations set at the state level. There are also industry standards that set the minimal bar. There's a lot out there that says no matter what your tolerance is from a performance standpoint, you must meet this minimum threshold.

From there it really is a collaboration between peers looking at best practices and understanding the characteristics of your system in order to be able to achieve the objectives of the system that you're looking

for.

I do want to call out since it was pointed at PG earlier that PG&E does not differentiate between wholesale and retail customers when we evaluate the replacement on our system. There's no consideration for what type of customer we're serving but we do have criteria based on age, and criticality of our infrastructure that help us determine what the right scope of work is for replacing our assets.

I would highlight that PG&E's been pointed at as being building up too much breaker and a half but out of the utilities in this room, PG&E has the lowest percentage of breaker and a half configuration in its infrastructure mainly based on the fact that we have a history of pulling the other many different utilities that have different standards along the way so we have a very diverse cross section of existing infrastructure.

So we operate with on what I would consider to be possibly a more legacy configuration and in some instances where opportunity arises, we look to bring up to that industry best practice if reasonable.

MR. THOMAS: I know we have sets of questions, is it okay if we just get out of line or -- I'm not sure.

MR. DOCKHAM: It looks like it's me. So I just wanted to go back to the earlier discussion that we were having about maintenance practices, standards, procedures

and just highlight that our concerns are expressed in our introductory comments and what I've heard is a lot of kind of merging of terms and it's really important to use the defined terms when we're talking through this today.

So the maintenance practices, I think that are the domain of the investor owned utilities are those confidential documents that it sounds like may be available in some form. It seems like there's some willingness to go down that path.

What we haven't heard yet is pursuant to the CAL ISO tariff where it indicates that these maintenance practices will be developed as appropriate and so what we'd like understood is what defines as appropriate?

When we get into best practices is that part of the maintenance practice or is that outside of a maintenance practice? It sounds like maybe it's a procedure because it's running through the transmission maintenance coordination committee but we don't know.

And so -- if so those are guidelines and if they're going to be represented as a practice, we need to understand that they are a practice and not a guideline. So I think it's really important to use the defined terms and I'll just leave it at that and we're still mixing and merging that today.

MS. LOOKER: Thank you, this is Geneva Looker. I

just wanted to respond to one of the things I believe that Mr. Nelson said -- I could be wrong about that -- about how the NERC standards, you know, the compliance with NERC standards goes through the TPP.

And at least from what we have seen with PG&E that that is not always the case. That many of their capital expenditures are for compliance with NERC standards, you know, such as the physical security which I believe also you have. I don't know whether yours as Edison goes through the TPP or not, the critical infrastructure protection.

The -- and the LIDAR, I am not sure but isn't it true that part of that is because when the lines are not in the official place where they should be that the voltages you can't put as much power on them as the TPP in using its models thinks that it can have.

So you know, this is all stuff that is very important to the reliability of the system but we don't see it going through the CAISO. Understanding that yes, you're responsible from doing it but there should be some oversight. There should be some recognition from the CAISO that this is all important for the reliability of the grid and that's something that we are concerned about.

MS. MAPES: And this is Katherine Mapes. I just wanted to address the idea that a lot of this information is provided to stakeholders in rate cases. And I first wanted

to say that in many cases to the extent that's true it's provided in confidential settlement discovery.

I think it's our goal in all of these cases to settle and I know that that's the Commission's goal to encourage settlements as well. What we don't want to do is get pushed into a litigation tract just so we can get public information on transmission planning.

And I second wanted to say that settlement discovery or even when it is litigation discovery is after the fact -- after money has been spent and projects have been committed and put into rates. So in our mind that's not making this information truly public, it's an after the fact examination that's already been done.

MR. GABBARD: Can I respond to that real quick? I would just like to clarify that PGE's recent TO filings have been litigated and we've gone through that so not confidential for all deliverables that have been requested through discovery and we have provided our what are deemed called our maintenance practices, our policies for the asset management investments and those were public in those transmittals -- I'm sorry I just wanted to clarify that.

I also wanted to actually add one point is that I continue to hear that TO filings are the rate filings articulated as after the fact expenditures. I do want to clarify that forecasts are included in those rate filings --

not just forecasts for capital additions but also we've historically supplemented with forecasts for capital expenditures that expand out in future years.

And for transmission investments I'm sure you're all aware that a given transmission investment can take many, many years to implement. So we do have forecasts well out into the future.

MR. NELSON: And just for clarification too, I had in mind data requests that were part of our normal process of our rate case before it was litigated. We have a four and a half plus month window where any participant can come in and data requests and general data requests are shared amongst everyone that's an intervenor. And likewise, our rate cases do look out at least a year forward, but again we've got a proposal in front of the Commission -- it was approved, suspended but approved, that will look out five years to sort of fill in that gap and give a five year issue.

And you know if something pops up in that five year timeframe where people think, you know, boy why are you doing this? Wouldn't it make more sense to do some sort of capital change or topology change. It's our hope with the five year window people can take that information and go over to the ISO's TPP process and say, you know, Edison is about to do this maintenance and compliance spend, we think

you should be changing grid topology instead and the ISO can have hopefully five years or four years a piece to look at that and make a call on whether yeah, they want to change the topology or no, they don't.

Edison needs to do the maintenance compliance spend.

MR. THOMAS: As far as timing goes we're kind of getting through the big boy part we were trying to get through this good set of questions. I think we've really kind of worked our way through question 3. A lot of what I'm hearing is starting to delve into some good discussions that are going to arise with question 4.

And we have one more question here -- one objective question here and then maybe take a small break if that's alright.

MS. BONE: Yeah, that's fine. I just wanted to know from the three IOU's -- do you have maintenance practices that are required by the CAISO tariff? Are they all written down in one place?

MR. SPEER: Maybe we do, CAL ISO does audit our maintenance practices inspections and what we do in the southern half, but I think yearly. It's been a while since I've been in that realm, but the ISO does audit our maintenance.

I don't know what term you want to use -- their

practices and procedures but the CAL ISO so we have a file plan on our maintenance procedures on the ISO and they're audited regularly just to make sure we're in compliance.

MS. SWITZER: So that file plan that CAISO has is not public to date?

MR. MILLAR: What Will is describing is separate from a transmission planning process. We have an obligation to ensure that utilities have maintenance practices in place and that they're actually doing them. That's a piece of the legislative responsibility of the ISO.

So to do that our maintenance standards list all the areas where there should be practices to insure that maintenance is being done and on an annual basis we do spot audits to ensure that the maintenance of various equipment transmission and substation equipment is being conducted to ensure that that equipment is being maintained to good status and is available to provide service.

That focus is to ensure that the system is available to serve customers. It's not a transplanting exercise, it's a separate process to ensure that the system will be available.

Now there is a committee made up of utility representatives, the ISO and other members from outside that include representatives from various organizations. The requirement to participate in that committee is that they

actually have a background in maintenance. It's meant to be an engineering exercise, not a rate-setting exercise.

And that -- like I said that's a separate function from transmission planning -- so we do ensure that the utilities have maintenance practices in place and that material is considered confidential and it would be the utilities that would be the ones making the decision of what, if any, material to release or not.

MS. SWITZER: But the standards are they in the tariff or are they in like a BPM?

MR. MILLAR: The transmission control agreement has a standard attached that identifies all of the areas that need to be addressed. It doesn't tell the utility how to address them but it does list --

MS. SWITZER: That gets to the best practices that they develop and then all that information that they give you for this is confidential.

MR. MILLAR: Yes.

MR. THOMAS: Do we have one final question member here?

MS. SWITZER: Well we'll take a 10 minute break if that's alright. 10:40.

(Break 10:35 - 10:47)

MS. SWITZER: So it's going to be

a good conversation going and I know FERC staff has some questions. We're going to keep going but we're getting through a good amount of the questions so I just wanted to let the audience know that I think we're going to take questions and comments in the afternoon after lunch if that's alright. We'll allow a little more time after lunch for that.

MR. THOMAS: So it looks like we have everybody back. I appreciate it. I think as Laura said we've started a real good discussion, I think some issues and some topics are coming to light which is the intent of this Conference. And some of the questions that were arising I think are really turning into a good segue to question 4 -- that's where we're going to begin this next session.

But I wanted to take a quick step back and then ask sort of a general question. I think this is somewhat going to be directed at CAISO and the PTOs but I think we could really use some CPUC assistance on this.

So I want to take the question of going -- take a moment to kind of explain, take a step back. There were discussions about the bifurcation of responsibility or the responsibilities of the PTOs take, how they take it, when they look at maintenance -- what they look to do in the criteria they operated under.

I wonder if maybe you could explain the division

of responsibility, between CAISO and the TO's as CAISO came into existence, essentially the history of how we got today's bifurcation and what those responsibilities mean and the reasons for that division.

And I think that the later part is kind of going to be the critical one. So I'm kind of asking for a little history lesson here with the reasons why we have a dividing line between maybe where we have maintenance issues and policy issues as was heard because we have the CPUC representatives here, it might be valuable to have them to come up with a system in doing that and so I think we maybe start with CAISO, allow you to go down that line, have the PTOs talk and if there's anything to be added based upon what we hear from CPUC it would be great.

MR. MILLAR: Yes, it's Neil here. I do have the disadvantage of not having been here when the ISO was recently created -- ISO for 7 years. However, I think our history is fairly well mapped out including in our comments and to the PG&E complaint -- the complaint against PG&E about the 890 processes.

Going back though, to the creation of the ISO, the transmission control agreement between the ISO and PTO's barely lays out the planning responsibility being the responsibility of the ISO -- apologies, and the maintenance and maintaining equipment on an ongoing basis to its current

capabilities being the responsibility of the transmission owners.

There is more details certainly flushed out in the ISO tariff through the development to comply with Order 890 and later Order 1000 and we believe those provisions have always been crystal clear on transmission planning, enhanced expansion and reinforcement requirements being with the ISO and the maintenance including replacement that end of life replacement is specifically called out as a maintenance activity with a responsibility to the utilities.

Now, that does not mean that they are not coordinated but those were the delineations. Now, the focus at the time was to provide that independence on transmission planning activities to insure that the system was developed in a way that provided open access to all.

And to be frank, some of the maintenance issues we're hearing about don't sound like an access issue, but that was my understanding and through the review of the material that's my view of it.

MR. WILLIAMS: Gridliance was not there at the beginning and we're kind of new but I do have a couple of observations. You know I don't think there's anything unique about where CAISO is as it relates to maintenance. I think most RTOs in the country really don't look at

maintenance as a function that they monitor.

They might coordinate, they leave that to the owner of the facility to be responsible for the proper maintenance and care mainly because the RTOs don't want to take the risk because there's a risk around asset management and asset ownership and so if there's prescriptive procedures and policies I think in a lot of cases it puts a lot of the risk back on to the RTO and they just don't have the visibility to understand age and condition, how things operate, how does this operate and they want to know what's going on but they don't necessarily want to direct what's going on.

So I don't think CAISO's much difference than SPP, PJM, MISO or ERCOT in that shape. So I think all these conversations are very, very important. I think there are visibility issues that need to be implemented.

I think local planning is important for stakeholders to be engaged in and maintenance fits into the local planning. So I think the need for some transparency at that level is very, very important so I applaud what we're trying to do here.

MS. CABBELL: This is Dana Cabbell. I don't really have anything additional to add that what Neil delineated between message planning and asset management and where that difference shows up in the TCR and the TO tariff

and you know, you agree now is probably the time for that transparency on the maintenance projects and so again that's why we submitted a TMCR for that purpose.

MR. NELSON: And just two little follow-ups. There's also an issue that I've heard in these discussions about capability and staffing and expertise and it's my impression -- I don't want to speak for the ISO that they're not geared for sort of the routine maintenance and how that would work and that level of -- of singular focus on both the individual tree within the forest that's required for someone who actually owns the assets and needs to know exactly per manufacturer's instructions what the requirements are.

MR. MILLAR: Actually, if I could just -- it's Neil here, if I could just step back in for a minute. Jeff did bring up one point that I probably should have touched on was that to take on the maintenance, developing the maintenance actual requirements projects and more importantly approving maintenance or at times not approving maintenance requires far more detail and far broader depth of the maintenance staff.

Our broader access to detailed information on condition and age of every asset on the system and also a completely different liability perspective on what risk is the ISO taking on by either approving or at times presumably

not approving a recommended maintenance project.

So that's where we get very concerned about the suggestion that the ISO should take into its transmission planning process maintenance activities because we do have obligations around the consequences of our planning decisions and if we take on maintenance decisions then that takes on a completely different perspective around not only that technical information but also the consequences.

And quite frankly, the staff in the field on a day-to-day basis, that's a very difficult prospect to hand over to another organization to take on responsibility for their maintenance activities.

MR. NELSON: And there was just one other thing that you touched on today. I want to amplify -- non-discriminatory access to the grid. I feel that we're doing excellent in the CAL ISO's and not to mention that I'm not aware of really any complaints of access to the grid through the interconnection processes, through the ISO's transmission planning process.

So part of the functional split -- I'd have to say has been a grand success in addressing the fair access and discriminatory open access.

MS. SWITZER: I just wanted to remind people on the phone to please put your phones on mute -- it was supposed to be a listen only line but apparently technical

difficulties. Please if you're on the phone, mute your phone, thank you.

MR. SPEER: Yeah, I have similar views. I think that really goes to the why, you know, yes our history and why it's split up that way. It's really that that visibility and the engineering day-to-day access to that equipment and really those maintenance plans, inspections -- you know we have condition based maintenance on our system that's monitoring.

We have full staff's dedicated to just that asset management function and you really need that granular visibility that the ISO doesn't have at this time. I mean that's one of the reasons why it was split that way. And it's true we own the equipment, we're responsible -- the liability question. We're responsible if something happens -- a transformer catches on fire, things like that, that's in our purview so.

MR. THOMAS: Thanks, I support what's been communicated.

MR. GABBARD: I don't have anything additional to add. I think all of those main points are spot on and PGE shares that same perspective.

MR. THOMAS: And I know I added if CPC wouldn't mind commenting if you would.

MR. BONE: I think Katie, do you want to start?

MS. MAPES: Sure. I think we in our complaint did a review of the CAISO'S tariff's as it existed over the years and we understand that these maintenance projects were never submitted to the CAISO but we think that the CAISO tariff and the filings that were presented to the Commission had some ambiguity in how they projected it and I think that over the years it's become clear to stakeholders that the transparency is less than we once thought.

MR. DOCKHAM: So I think with regard to question 4 I would say no. You know the tariff simply points to the transmission control agreement which is the governing document for all of these alternative transmission projects that are being done.

I'm not aware that the business practice manuals speak to maintenance at all and while I think the transmission control agreement is a good start, and there's some good ideas in there, they need to be significantly built out and I'm glad that we're having that discussion here today.

MS. BONE: So to echo Katie's comments about what happened in 2007 and 2008 with the Order 890 development, you know at that time we really understood that the CAISO tariff, the compliance filing that was made would require most, if not all, projects to go through the CAISO and it really wasn't until about 2012 when we saw PG&E's

transmission rates going up exponentially with no significant capacity additions that we realized that they were putting this vast bulk of materials under the heading of something other than CAISO or self-approved projects.

So I'm -- so we're concerned about that. We're concerned about what was misunderstood or perhaps misrepresented back at that time and we're also concerned about this current dichotomy that seems to be explained between transmission planning and asset management as if there is no planning involved in asset management when we're being told that in fact, you know, PG&E's looking ten years out.

Is that only for your CAISO additions or is that also for asset management? And if you're looking ten years out planning is necessarily involved in that asset management so this kind of dichotomy is -- its non-existent.

There's planning for asset management, we need to recognize that, it needs to be transparent. I will add that, you know, constant reference also to the rate cases being an appropriate opportunity to see this stuff is just ridiculous.

We learned in PG&E's rate case that in fact they're advancing projects that aren't anywhere in any of the plans that they file with us that they provided to us in

discovery -- over 800 projects costing about 300 million dollars for one -- for two years.

So there are projects that are showing up at the last minute that aren't even disclosed in the rate case. So I think that, you know, how we got here -- misunderstandings, misrepresentations and where we are today we need to acknowledge that this asset management is planning, they're spending a lot of money and there needs to be transparency.

MS. AMOS: I have a question, it's Angela Amos from FERC. Speaking of the listing of projects that you described as an example, do you have any ways to -- how would you evaluate those projects? How would you prioritize if things were more transparent the way that you described?

MS. BONES: Well what we're looking for is for the utilities to explain to us how they are prioritizing those projects. We aren't in a position to do that and we aren't getting that information either.

So it looks like they're selecting projects based on -- do you want to answer this, okay.

MR. DOCKHAM: Sure, so our suggestions is that the business practice -- or excuse me, the unified planning assumption document that starts the process in the CAL ISO's transmission planning process is the way to go. So they identify the criteria that they're going to use to study

the4 system for expansion purposes.

So N minus 1, N minus 2, G minus 1, G minus 2 criteria loads on the transmission system. Everybody understands what those criteria are. For the other types of transmission projects, you know, we've heard a lot today about transmission line, NERC requirements, having to raise the conductor height, changing out poles that have reached the end of their useful life, you know, coding transmission towers.

There should be a practice or a procedure that defines precisely what the criteria are going to be for recoding those towers, for replacing those poles, whether it's destructive or non-destructive testing. This is how we're going to do it.

And I don't see any of us sitting in the room and saying, you know, your criteria have demonstrated that these poles are defective and need to be replaced. We just want to know that that's the basis for the change outs that are taking place and today we don't have that opportunity.

And so like I said, I think what the ISO has put in place in terms of the criteria is a good start but it needs to be augmented with these unified planning assumptions for this huge amount of work that's being self-approved by the IOU's right now.

MS. AMES: Any follow-up here?

MR. DOCKHAM: Sure.

MS. AMES: It's Angela again, obviously. So I'm hearing that there are some categories of maintenance or other activities that the ISO just wouldn't be a part of right? But for the things that wouldn't fall under the ISO's purview, how would those items be prioritized and reviewed were they more transparent?

MR. DOCKHAM: So today in the TO proceedings we see a list of, you know, Traci mentioned 800 projects that are segmented by major work category. So if there were a standard -- if there were a practice that defined how those projects were going to be reviewed and approved, you would be able to validate those projects against those practices or standards -- that's what's missing today.

MS. AMES: The criteria?

MR. DOCKHAM: Correct.

MS. AMES: Thanks.

MS. LOOKER: This is Geneva. Just to expand on what Dave was saying -- we understand that a lot of this stuff should be done by the TO's, it's their assets they need to make sure that they're replacing it and keeping it in good working order.

But what we have been -- had trouble doing was getting from them the prioritization of the ranking of why they were picking the projects they were picking.

And, you know, we tried in discovery to get some of this. We did finally get a little bit of this but it's not nearly enough to determine, you know, why have you ranked this as number 1, but you don't have a project planned to replace that?

If that's really the worst performing one or the oldest or its condition is bad -- it needs a lot of maintenance, why isn't that in your five year plan?

Or let's say with Edison, they have a whole bunch of projects that they put into categories that they call blanket categories so without further discovery to even get underneath to see what is included in those projects, it's hundreds of millions of dollars being put into the ISO TAC that without discovery, without real work and you know, we have learned you have to really know how to ask these discovery questions to get the right information.

And that has taken us probably three or four years to get to that point. So if we have some kind of a transparent process whether you know, whether it's under the ISO, whether it's not under the ISO, but it's just each individual PTO has, you know, has to abide by -- say we'd p-refer a unified plan where each of them has to provide this information but it would involve the criteria they're using, you know, how they're ranking and prioritizing their facilities, which ones are in their plans, if they're ranked

high and they're not high and they're not in the plan, why not?

I understand there might be some difficulties with where the substation is placed or you know, we understand that but we need the information. To have these millions of dollars going in that are -- the rate payers are having to pay for, that just is not right.

MS. AMES: Okay, so insomuch as this would be more of a dialogue, the information would come from the PTOs, be presented through whatever process would be established in theory and you disagree, then what happens?

MS. LOOKER: There would have to be some protocols for that as well.

MS. AMES: And I'm not, I'm trying to ask because the idea of the workshop is that we can collaborate and brainstorm and all of that so don't read too much into my question.

MS. MAPES: So I think if I can answer this, I think that there would be a several stage process and we follow it closely what the Commission did in its PJM order where it asks for three meetings.

MS. AMES: We want to stay away from that, we have an ex parte issue with PJM.

MS. MAPES: Okay, and then what we envision and what we will present in our post-Technical Conference

comments is an iterative process. We're not looking to substitute our judgment for that of the PTOs. We understand that it's their system and they have an ultimate obligation there, but we're looking to first give input on the -- on the assumptions and criteria than to give input on the projects themselves and potential solutions.

And then finally we would look for dispute resolution process. We'd want to be able to bring both substantive and procedural disputes before the Commission or before a dispute resolution process as laid out in the tariff. So if there's a disagreement we think there needs to be a process in place to handle that disagreement.

It wouldn't be well we say this so we're right, it would be, you know, we give input as collaborative over time and then finally there's some sort of dispute resolution and I'll add that this is really what's lacking in the current structure where we give information in the rate cases -- there there's no dispute resolution, there's no opportunity for collaboration. It's merely a one way flow of information followed by at best, a prudency challenge.

We would submit that that's the worst way to handle those kinds of disagreements.

MS. AMOS: Other thoughts?

MR. NELSON: Well yeah, within our TMCR so we --

MS. SWITZER: I'm sorry, could you just speak up a little bit more?

MR. NELSON: Yes, within our TMCR filing we have multiple feedback loops where we release a draft plan, give people a chance to review it. We have a stakeholder process. We then are given feedback from our stakeholders within -- with written comments. We then have a chance to review those and put out a final report on what we've done with that.

As amended we have an escalation process where it can ultimately be brought up to medication. And then we have an opportunity post-final report basically for people to provide feedback on what we should be looking at -- final comments on the report, but more importantly feedback on what we should be focusing on for the next iteration.

So in this process there would be we had an example here of a breaker and a half versus sectionalization. So we might put out the draft report that says oh we're going to breaker and a half this. People in our stakeholder process may ask questions -- well why are you breaking and a half this section, doesn't sectionalization make more sense? I'm not a transmission designer but I'm just using examples.

We want to hear that feedback because it may be a very reasonable idea and we'll take that into consideration

and our final report may come out -- hey, we changed it from the draft. We're sectionalizing this because of the feedback we got.

We're not. Or maybe we looked at it and there's whatever -- whatever the situation is it's not going to work. So that's our process and then ultimately multiple years ahead in our process if they think it should really be kicked out of the asset management into the transmission planning process, at lease with a five year window there's a chance to kick it into that process or something completely different than we were planning and then ultimately if it makes it into our rates, then ultimately we're back sort of to that last step of a challenge to those costs, ultimately, through some sort of state, but that's sort of the last step after we've gone through these sort of five year process.

That's how our process works as approved but suspended.

MR. THOMAS: Is there a question over here?

MS. MAPES: I'll start. While we appreciate Southern California Edison taking the initiative to file a process however we think that it's still lacking in some respects. The key one from my perspective is that Southern California Edison, as I understand the process, seeks to present solutions to transmission needs at the same time as it first presents those needs so we're not getting to review

the criteria and assumptions and models that underlie as identification of transmission needs.

And so for us this process isn't iterative enough. It doesn't provide the two-way flow of information and collaboration that we'd really like to see. It provides essentially one round of stakeholder comments on the current draft and there's a final round that will only be taken under account in successive years.

We'd like to see multiple rounds of comments on the draft in a given year before we take it into the FERC process. And I'll pass this down to Traci.

MR. NELSON: I just want to nuance on a word there. Again, we don't view this as a planning process. Yes you make intentions and budgeting and have events that are going to take place in their maintenance. We don't view this as transmission planning.

So with that said the degree of models and the technical input that go into true transmission planning in our assessment don't come into the main nexus, it's a different type of activity. So I do respectfully disagree with labeling these maintenance activities as transmission planning.

MR. THOMAS: I can add a follow-up to that, I just want to explore a little bit what I heard Katherine and maybe as Jeff responded. The question that arises to me is

it sounds like, you know, again we talk about information sharing. It seems to be kind of narrowing, drilling down to kind of what it is -- it might be the crux of our discussions today.

And if there would be some sort of resolution to do that what is your opinion on how that would affect not only the transmission maintenance practice they do as far as duration goes, the duration of that effect on CAISO'S transmission plan. Do you have a sense of kind of how all that plays in because I get a feel if I listen to it long -- and we're talking about multiple rounds of iteration.

Can we meet the timelines to be timely and active in transmission planning as well as mirroring that up with maintenance activities?

MS. MAPES: Yeah, and we'll go into more detail about this in our post-transmission post-Technical Conference comments because we have a proposed process in mind that syncs up with the CAISO transmission planning process.

So in our mind it would sync up with both the CAISO transmission planning process so that if something needed to be kicked over to that process we could do that and it would sync up with the TO's rate case schedules so that projects would be reviewed before they went into a particular rate case.

I think that the CAISO transmission planning process is a -- exactly the kind of iterative process we're talking about and there are opportunities to synchronize with that process to say that -- and we envision something like an 18 month process for each planning cycle where you start with the unified planning assumptions in one cycle at the same time as you're looking at the draft final plan for this previous cycle so everybody is kind of on the same page as far as these projects move through -- does that answer your question to some degree?

MR. THOMAS: I think, I mean a synopsis here would have been helpful -- again we're trying as we go through this and create maybe not only information sharing but ideas and kind of that synopsis is helpful here, we wouldn't want to take anything out of context and be sure if there's a resolution to be gained rather than waiting to post at the Conference hearing it here and seeing if there's some resolve they can get to would be helpful.

MS. LOOKER: This is Geneva Looker, but to respond to Jeff's comment that you don't really plan for maintenance -- I would respectfully disagree with that. You keep using the term maintenance as if -- as if that doesn't involve planning.

And really I like the term you used initially which was the asset management. These are the assets you

have, you have to manage them. You have to plan to manage them which means you are keeping track of outages, you're keeping track of whether they're in a good condition or not.

You're keeping track of how old they are. You're keeping track of the manufacturer of the circuit breakers. You're keeping track of all of this stuff sometimes through maintenance practices, sometimes through inspections, whatever you need.

Granted some of this does not involve modeling -- power flow modeling but you have the records that inform your plans for asset management. You obviously have plans of what you're going to work on next year, the year after. And that is what we have not been getting access to.

It's the criteria, you know, what is the age of something? Are you weighting that 50%, are you weighting the condition of it 20%, whatever the assumptions in criteria might be?

And then the list of okay, we rank all of our assets. These are the ones that appear to be in worse shape. We need to fix those first.

(Interruption -- music playing over phone.)

I'm finished.

MR. THOMAS: Okay, because I did want to comment and I appreciate I think there's -- I don't want to

necessarily be in a -- and we appreciate the enlightenment of terminology back and forth. I don't want to necessarily want to get down that versus -- I think we might have lost a little bit of focus on question 4.

And Mr. Dockham you mentioned that your answer if I heard you right was no, that the TCA's or the BPM's don't provide enough guidance or clarify. So I wanted to kind of build on that question -- continue moving forward here today.

And take a moment, maybe a couple of seconds kind of let -- if you have ideas, what that is because you talked about and mentioned the word built out. Can you give us some high level topics of what would do that?

You also mentioned the word, you know, there could be potential ambiguity in the terminology within the current TCA's as approporiate?

MR. DOCKHAM: Correct.

MR. THOMAS: Maybe define for us what that means -- what you would see that mean and maybe some ideals for us of what a build out would look like?

MR. DOCKHAM: Sure, so as appropriate it should cover every category of work for which transmission access charge recovery is being sought. In terms of building it out amongst the things that we would like to see is a five year projection for all of the projects contained within

each of these major work categories and I don't know to what degree Southern CAL ISO, or San Diego Gas & Electric utilizes the same kind of structure to identify their self-approved projects.

But let's just say for example within the substation asset category or the line maintenance category that there's some hundred projects listed there and if in any one year the criteria for which those projects are advanced as clear and it's essential that they be replaced and for whatever reason in year 1, 2 and 3 for which these things were identified, these projects aren't completed but other projects are such that we're spending the same amount of money in that major work category that was requested in the TO proceeding, what kind of back log are we generating?

What kind of adherence to budget is being accomplished? We can't see any of that now. We make no secret of the fact that one of the major concerns that we have here is the rate of increase of TAC and we think a major contributor to that is the lack of visibility into the projects that are being scheduled, deferred or substituted.

And so we'd suggest that that's a huge improvement that needs to be addressed immediately -- does that help?

MR. THOMAS: I think so. I mean I just want to make sure we come out -- we're talking about frameworks, and

we've gotten an idea of what people are thinking when they bring ideas up.

MR. DOCKHAM: I've mentioned the unified planning assumption's document as a template and whether you, you know, refer to SF maintenance's planning or not I agree with Geneva. I think clearly you're planning to manage your assets, but the document ought to identify upfront all of the criteria upon which you are evaluating replacement and upgrade needs.

And stakeholders in the process can easily determine whether those criteria are being appropriately applied in the projects that are being recommended.

MR. THOMAS: Is your suggestion in that regard then -- can it be more focused on the transparency and maybe we use terminology comparability and things like that but not necessarily to establish one's better case in the prudency challenge?

MR. DOCKHAM: Could you ask that question again?

MR. THOMAS: Sure, it's more -- is the focus about the type of build out as you've explained or heard quite a few things in there that we want to focus on, at least transparency. The thing that's happening, the reason it's happening in the decisions that are being made but not necessarily focusing such granularity that we would know cost items, breakouts, this decision, that decision such

that if someone wanted to use the Commission's potential processes or planning as a prudency challenge because I'm of the opinion that's not what our planning processes were about, that's the "B" stuff.

I'm just curious if the mindset of having that level of granularity or if we just kind of stop at this floor more than transparency floor.

MR. DOCKHAM: Let me try and answer a couple of ways. So I think there are a series of projects that are routine that will be approved with little to no review and little to no objection and I'll site the projects that were mentioned at the very beginning of this Conference.

Not much to object about there -- there's another set of projects and Neil mentioned this -- that you know you could have a substation project that fell within the purview of the PTOs or within the purview of the ISO.

That one ought to have some ability to at the end of the process run through the alternative dispute resolution process.

MR. THOMAS: Okay, thanks, I appreciate it.

MR. GRIESS: I think Dave really hit on the important piece. I think there is a -- there is a request for more transparency but because there's been little or no transparency until now for what's becoming a majority of what's feeding the TAC cost, then there does become a

question of prudency. Are they doing the right project? Are they doing it at the right time? Are they spinning the right amount of money on it? And so that level of transparency helps answer those questions and I think that's what's needed.

MR. THOMAS: Okay.

MR. GABBARD: Just real quick. I'd be remiss if I didn't chime in on Chris's earlier point. I think it's very important to acknowledge that time is of the essence in many instances and that no matter what aspect of this conversation we're having the number one guidepost should be around safe and available access to the transmission system.

When I say available I mean it's there and its operating to be able to meet the needs of our customers and so there is an aspect of this subset of investments that we're talking about where assets have actually failed in place.

And we as the utility have the obligation to maintain availability of that grid so we're doing everything within our power in order to restore that service. So you know, there is an example where that asset fails we're in a situation where we're exposed to an N minus 1 minus 1 type of contingency.

So we need to manage that risk effectively and it's moving towards putting a 14 month process or whatever

the process may be on the critical path of those actions is cause for concern when it comes to maintaining the availability of the grid and in many instances the safety of the greater State of California.

So I don't -- I didn't want to blow by that. I want to make sure that we're all holding that as a cornerstone in this discussion because it's something that we hold dearly as transmission owners.

MS. BONE: And I don't think that we have any disagreement about that and that basically would fall within the class of assets that Dave Dockham was talking about. We have no intention but we don't think that those are emergency replacements or what's getting us to a billion dollars, so they're a very small fraction of what's going on.

MS. GORDON: This is Danielle Gordon. Without touching on some of the questions that we have to go over later this afternoon, I keep hearing about increases to the TAC dating back to 2012 even. Can you speak to -- without going into too much detail whether you're seeing increases in the overall TAC, are you seeing increases in the regional component or at the local component or both?

MS. MAPES: Do you want to take it Traci -- I can start. We're seeing increases in both, it's increasing across the board and the way it's split up is generally in

the high-voltage and low-voltage and NCPA's customers are connected in both and we're seeing significant increases.

MS. BONE: However, I will point out that we are also seeing a trend where fewer and fewer projects are going through the CAISO process and the percentage of self-approved projects is going up significantly.

MR. GABBARD: Just to clarify for the record. I want to touch on two points. First off the phenomenon of requiring additional investment in the transmission infrastructure is a natural occurrence based on the fact that a lot of the transmission at the structure is reaching the end of its useful life.

A lot of the infrastructure that we had in the State of California was built just previous or just post-World War II. We have assets with the useful lives in the -- some newer technologies in the 20 year range, but 50, 60, 70, 80, 100 year range. We're reaching that wave in the utilities sector where infrastructure that was originally built out with the build out of the transmission grid is now reaching the end of its useful life and going through that lifecycle replacement.

So we are increasing our investment in order to actually maintain the performance of the grid as we're obligated to do. I also want to clarify a correction that at least within PG&E's service territory the percentage of

our investment in our transmission infrastructure for projects that were approved by the California ISO is actually increasing and has done so over the recent years, so I just wanted to call that out.

MR. SHEER: Will Sheer, the other piece I'd add too is really the fire hardening activities at least specifically for SPG&E. California has been devastated by wildfires, everybody knows. We have been investing in those activities to prevent that occurring again. So we've seen an increased cost in fire hardening our transmission lines in those fire prone areas, so that's an important investment that we're going to make.

MS. AMOS: Is that the kind of investment -- Angela again, is that the kind of investment that would be time sensitive?

MR. SHEER: Yeah.

MS. AMOS: And so it wouldn't necessarily fall into the bucket of projects for which there would be concerns?

MS. BONE: It would because it's a massive investment and it's going to be -- it needs to be spread out to some extent so the question is over how long and how much is done each year?

And I think that both Will's comment as well as Dave Gabbard's comment about you know, the long-term need to

replace basically all of the assets in the system points to the very fact that we need to be planning for these things and that there needs to be a process in place that we can participate in to ensure that the planning is happening at the right time on the right assets.

MS. AMOS: Can we explore this point a little bit? The fire hardening element since that is such a big concern these days -- where we draw the line between the longer term planning or you know, the next 50 years of the grid and the short-term lead of protecting against current risk?

MS. BONE: And I think that that goes to kind of the corporate management of risk and looking at all the priorities that the utility has to meet in figuring those things out so it's not something we have -- that we have an answer for today, but again it needs to be a transparent process where we can balance all of the various needs -- fire hardening and other asset replacements.

MS. LOOKER: This is Geneva Looker. I'd also like to point out that fires are not new to California so over the years of building transmission facilities fire hardening should have been considered over time.

Granted new technology is available, new things are available that you now want to install but this is something that should be part of your planning process

continually, all the time so you know, I wouldn't term that as emergency. The emergency was as lines and poles are destroyed in the fire you have to get them back up and get them operating -- that's emergency.

But the fire hardening is a planning process that you have to look at, decide how you're going to do it, figure out which areas need it first or are most prone to fire and then budgeting and then, you know, there are a lot of elements that go into that fire hardening.

MR. SHEER: Great, and some of those to your earlier point weren't available at least on the lower voltage and that's a lot of what we're doing today so that's the change out. At least for one of our projects did go through the CPUC process.

We had a permit to construct for one of our larger fire hardening projects so there was transparency there was, you know, that was a very long proceeding. Eventually we got approval but that's, you know, three years longer than what we probably wanted to start. I mean that's what happens. It just delays getting started and you're just -- we're at risk, our customers are at risk, so.

MR. DOCKHAM: Is that, so I mean we can't do anything but comment San Diego Gas & Electric for some of the work they've done, probably some of the most innovative in the nation. I mean they've hired fire departments,

they've invested in weather forecasting to better predict when the Santa Ana winds are going to come.

They've put practices in place to shut-off lines in the rural wind prone areas, but where we've seen in some TO filings is the capitalization of some of these costs so I have no idea what San Diego is doing but it would be helpful to understand, you know, who's paying for the fire department? Is that an expense or is that a TO expense?

In some of these others it is the planning -- the development of the plan, is that a capitalized expenditure because we have seen disaster plans capitalized in the TO process. So all of this I think bears on the rate of increase of TAC.

It's just the lack of transparency into the planning processes that are going on. It doesn't allow this to see how these things are being handled up front and it indicates that there is plenty of time to work through all of the details as these plans are being developed because they are long-term in nature.

MR. SHEER: I don't want to go through -- down a rabbit hole here but I do appreciate the accomplishments of SDG&E. I just want to clarify two quick things. We didn't hire a fire department for one -- just to be clear.

And our costs associated -- we did hire fire coordinators -- ex-firefighters for California but those

costs are shown in our CPUC general rate case so we put those in. So there is the opportunity for CPUC to review those in our general rate case filing, one of them.

So it's not -- not that it doesn't exist -- I mean that is an effort we're going through right now. We do put in those costs and make them available and the reasons why, so.

MS. SWITZER: I keep -- different section, I keep hearing you referring to it as planning and PTOs are -- it's not planning, it's asset management. And this might take us all the way back to the first one or two questions about -- can we just again talk about how you plan for asset management?

I know that there's criteria, they're confidential right now so is there teams, you know within your companies that are in charge of this and how far ahead do you look and just maybe expand on the planning of these asset management for us.

MS. CABBELL: This is Dana Cabbell from Edison. Yes, I mean there are teams. There is organizations within the company that that is their sole purpose is to look at the equipment, evaluate the equipment, determine does it need to be replaced, when does it need to be replaced?

It does go through our population process that we've been implementing. So they are dedicated to be

looking at our assets and to determine when they need to be replaced. And its typically this type of work is a two to three year process.

The projects are identified, scoped, procured, constructed within two to three years.

MS. SWITZER: So you would agree that there's planning, you obviously have to plan for this asset management. There's different -- it's not very much different than transmission planning?

MS. CABBELL: Right, it's not transmission planning in the sense of what goes through the ISO process.

MS. SWITZER: Yeah, are there any concerns about keeping certain things confidential, if you continue to go down that route?

MS. CABBELL: I mean I'll have to go back and really dig in to what that information. Maybe Dave and Will might know, there's some of the projects that we get into like the cyber security and the physical security projects -- those we consider confidential, particularly the location and what scope is particularly for cyber security -- what are we doing to harden our system to prevent cyber bad acts.

And then also the physical security -- the understanding which substations are being identified through the NERC reliability standard related to physical security. Those substations, the locations are confidential.

MS. SWITZER: You do have criteria and you do have a team that's planning these and looking out a few years ahead?

MS. CABBELL: Yes.

MR. GABBARD: I'd like to provide a little color from an asset management standpoint. At the end of the day what asset management is doing is optimizing value so it's looking at the cost and the system related performance or risks that come out of a certain methodology.

When we manage our assets it could be a span across a long spectrum of different strategies. One can be as simple as run to failure. You never -- you don't proactively replace your lightbulb. You run that until it burns out and then you go and you replace it because the implications of that one lightbulb going out are de minimis and the most cost-effective way to manage that asset is to run it to failure.

On the other end they're assets that you can never have run to failure so you need to employ different strategies. And as the complexity of the transmission system grows that asset management framework has continued to mature.

I think asset management as a theory started in the '70's in Australia, but it's matured over time and as more and more of our infrastructure gets to the end of its

life we need to think more diligently about how we manage it.

Historically it's been run to failure or run to time. We're now moving towards run to condition and it's more of a predictive condition. And that condition is not just about the probability of failure but the potential impact of that failure. And as we move to that more targeted asset management methodology we really need to highlight the criticality of our assets.

So in some instances that information can be public in nature. In others, absolutely not -- I think the far extreme would be some of the criticality identified under NERC's set 14.

In others, we are really prioritizing okay, we can more aggressively proactively replace this asset because the impacts of it failing would cause this, this and this, having that transparency to the public actually expose us from a sabotage standpoint so that we have sensitivities around it.

Another instance we could say this asset the failure will have impact but the impact is negligible -- that type of information we would be more comfortable in making transparent. So it definitely is a spectrum, but there are sensitivities that we need to take into consideration.

MS. SWITZER: Like in the criteria and the sensitivity in the procedure is just available for everyone to understand but not necessarily specific locations or projects.

MS. LOOKER: This is Geneva Looker again. I agree with David in what he's saying that there's changes in how you do things but as he has said different assets have different criteria, different assumptions, different needs, different risks. All of that can be revealed and be transparent.

When you get into the details of which project and how the prioritization and the ranking goes and which projects get put into that, that might require some non-disclosure agreements or something like that. But at least that is the kind of stuff that we have been looking for in the TO cases was -- was that information and it took a great deal of work to get it.

When we did get it we still weren't in a place, in a litigation proceeding to explore and ask the questions well why this? Why did you rank this one above that and you know, okay you ranked it high, why isn't there a project planned for this but the one that's ranked 589 has a project planned.

It's that kind of dialogue we need, feedback, iterative process. The criteria, the assumptions and you

know, I don't think that the people here would object to some kind of a confidential process. I believe does the TPP have the confidential process when you're doing --

MR. MILLAR: At the ISO we have three levels. Our general planning process is fully open, transparent, published on our web. The next level of information is available through our under our non-disclosure agreement. And there is a third around a certain extreme of analysis that isn't made public, available at all even under an NDA.

MS. SWITZER: Okay.

MS. TEETER: This is Valerie Teeter from FERC staff. If I can kind of ask a follow-up question. It was helpful to hear kind of like at a very high level, how the asset management process works. I guess I wanted to dig in a little bit more to kind of get a little more detail on each of the steps that I heard.

So I heard that as part of this process you know you're constantly evaluating your system against a certain set of criteria. So, you know, assuming that those at least internally are documented.

You're identifying criteria that maybe aren't being met, opportunities for projects, scoping the project. I'm kind of curious what's involved in that stuff. Is it looking at different alternatives, is it identifying whether it may be something that goes to CAISO?

You know kind of developing the solution and then moving forward to actual construction and all this can take a year or two years depending on the project. Could you give me a little bit more detail maybe about how each of those steps really work so that we could understand what -- kind of what considerations come in at each level of the asset management process?

MS. CABBELL: So I'll start again, this is Dana Cabbell. So the organization looks at the assets -- let's say circuit breakers. What they do and as we've been talking we look at a certain criteria and we take it through a health index type of process, looking at the age, the criticality, the location and trying to understand.

And this is, you know, throughout the whole grid. And some of it is done on inspection also. So we identify, you know, which circuit breakers we need to replace and then we take it through the prioritization to understand the risk that if that breaker failed what is the impact?

So then you're starting to look at impact also. So we've come up with now a list of circuit breakers that need to be replaced. When I say scope it's really now of a more okay now it goes into engineering, now we need this type of circuit breaker, you go through procurement.

It's not scoping like you're looking at alternatives, it's more of the engineering scoping, this is

the size of the breaker going to the procurement process and then the design, you know, making sure that this new breaker fits into the old spot.

Sometimes you need to change the footings because now with the breakers different, you know, a different size or whatever, just by physicality not by capacity but it just -- or maybe smaller because it's new technology.

I mean so you have to engineer it to make sure it fits in to where you want to put in the breaker or the transformer so that's kind of what I mean by scoping and engineering, procurement and then you go out and basically have the crews construct it.

MS. TEETER: Is that similar for the other?

MR. SPEER: Pretty similar. I mean I think they probably all have internal committees. I mean ours is the substation equipment assessment -- the C team, so they meet regularly, they establish kind of that criteria for what, you know, what we're looking for -- what's the highest risk?

So it's the same kind of process internally. We're looking at what are the assets that are most at risk and the criticality and then going through that process then, okay if these are the type of assets we've identified, how many of them do we have across our system?

What's the plan to get them all replaced because that's planning -- that's transmission planning but that's

asset management planning but there is like, hey maybe we have 30 of these. We can't do them all in one year, it's going to take us 5 years to do it.

So we have those same type exercises and then it goes through the procurement and the construction.

MS. WONG: This is Jocelyn Wong from PG&E. The one additional thing that we do from a scoping perspective is that in addition to just identifying that single asset that needs -- that is the potential for failure and we will take a look at what else is going on in that substation to see if they can capture any other efficiencies.

Anything else that's also on the list for replacement, any other structure or any other assets within the substation that need to be addressed, safety issues, operational issues, we'll take all of that into consideration as we identify what the overall scope of work should be for that project.

MS. TEETER: Thank you, that's helpful.

MR. GABBARD: I do also want to highlight that asset management has a bottoms up and tops down aspect to it. The bottoms up is really looking at asset by asset based on criteria what is the most critical asset that needs to be replaced first?

From the top down standpoint we have some assets more so than others but we have failure data from our asset

base or from industry that allows to inform based on the existing condition of our assets what we can project failure rates to look like into the future.

And so what we need to understand is how much of those assets do we want or how proactive do we want to replace those assets as they age in order to avoid those assets failing in service and we need to understand the implications of that so we do modelings top down that say you know, at this investment level we're going to be able to catch this many failures before they occur at a higher level we're going to catch more, at a lower level we're going to catch less.

What are the implications to those various metrics that are -- that we care about and our customers care about and our regulators care about? Those are things like the impacts on safety, the impacts on overall reliability and availability of the system as well as impacts on the environment and other considerations.

And so we look at that holistically and we say, you know, employing the strategy in aggregate is going to have this kind of an impact on the overall company performance on a going forward basis. Where's our comfort level with kind of optimizing the investment level versus the expected outcome from those investments?

MS. BONE: Okay just to engage in a little ground

truthing of that -- the statements. We understand -- the CPUC would love to see all of the utilities engaging in a process where they look at all of the assets in a class, prioritize them, understand which ones need to be replaced first.

But in RTO 18 discovery, PG&E testified on the stand that capital addition decisions have been made primarily on a project by project basis rather than through a comparison of similar assets as a whole in order to compare projects and prioritize them and that it wouldn't be able to do a database search to do that comparison of similar assets as a whole.

And this goes to one of the issues that I had hoped to flush out a little bit more in my opening comments which is that even once we get this process in place, you know, we have agreement on what the tariff looks like, the data is lacking and the internal processes are lacking so that we need to -- we need to be moving quickly to make up for those date deficiencies and what's going to be required.

So there's going to be a major implementation challenge because today what is happening is not at all what we'd like to see happening in the future.

MS. TEETER: Well if I could just follow-up on that from what you've seen in your experiences is a less kind of I want to say, for less process in a way where it's

really looking at individual assets and whether they need to be replaced rather than kind of taking, you know, more like a cyclical type thing where you take a look every year or every however many months -- thank you.

MS. BONE: Yes, what we are not seeing the N to 1 planning or what's is 1 to N? I say it wrong -- I'm not the 1 to N planning, that we had hoped to see that it's a very ad hoc more subjective process.

MR. GABBARD: Two quick questions. I heard a representation that there was a cite from testimony but I didn't hear that it was an actual cite from testimony. And then I do have a question -- is there any concern about ex parte in that we are citing testimony from an active proceeding in front of the country?

MS. KIZUKA: I'm assuming that it's one of the proceedings that was listed in the most recent notice?

MS. BONE: Yes.

MS. KIZUKA: On that case.

MR. GABBARD: There's no concern.

MS. BONE: Right, and the transcript cites -- the FERC transcript cites 212 to 214, if you review those areas as well page 230.

MR. THOMAS: I will follow-up with that we do want to recognize what this Conference is intended to be and I understood there was supposed to be illustrative only

leaked in that regard, that we're not here to rebut or have a conversation about what that testimony's about.

MS. BONE: Absolutely. I think that the concern is that it's not just PG&E, we suspect that we're going to see this, you know, throughout all of them and it's not about the TO rate case, it's about getting a process in place and being aware that we have these major implementation challenges.

And, you know, that combined with the end flight projects is how do we quickly get our hands around all those issues?

MR. THOMAS: Mr. Patrizio before you go I do want to recognize we are kind of working through -- one of the things I wanted to mention is we're trying to get before our next break is through a series of questions and I think we've kind of been migrating, getting through questions 5, 6, and 7.

I want to kind of maybe plant a seed in your head if there are questions and we still haven't addressed those topics as raised in the agenda, we would feel free to do it but I think we started to kind of get into there and so for purposes of making sure we get good discussions throughout the day and maintain our timeline, I would much divert you beyond that but if there isn't anything else in there -- there might be a few questions I have regarding to 6 and I

might want to address that before we take a break for lunch.

So Mr. Patrizio with that you have a question?

MR. PATRIZIO: I do have a question and my timing is bad. I think my question was probably best directed at Linda who just stepped out. I'm not clear on how we're applying the ex parte rules.

I acknowledged TO 18 was identified in supplemental Technical Conference notices, but I am growing concerned that representations are being made and this is going to be transcribed and those representations are certainly CPUC's position in TO 18 but hasn't been -- those positions haven't been ruled on by a Commission and we have held fire and not rebutted each one as they have come in.

But if it's going to continue throughout the afternoon, we're going to perhaps, feel compelled to rebut them. There was a reference earlier about advancing 800 projects costing 300 million -- that's their assertion, it's not a fact.

And we've aggressively opposed it in TO 18. How are we going to deal with that for the rest of the day if we're getting these assertions being transcribed, being unrebutted? Maybe you as staff can consider that over lunch how we best handle that in the afternoon but at some point we're going to have to start counterpointing all of these things. I'd prefer to avoid it.

MR. THOMAS: Understood.

MS. FARINELLA: I'd just like to say at a high level that we need to stay focused on the questions here so if people could just redirect themselves to the questions that are being asked and answer those questions, I think that would help in a high, high level.

We'll think more about it on a detailed level after lunch.

MS. SWITZER: Are there questions on number 6?

MR. THOMAS: Yeah, we've been going a little back and forth. I think we've heard some topicality about how -- what are these types of projects, how they're determined. I think there was some discussion on that. Emergency projects weren't in question, I'm not going to go either way on that.

It was a great opportunity for illustration on what we talked about when we talked about non-transmission compliance and maintenance activities. One thing I kind of wasn't sure that I got is looking at question 6 and the sub-part question is does each PTO differentiate between transmission where the maintenance compliance activities that require immediate action and those who don't?

And I think we talked about those that do -- emergency type things you would only take, you know, some things that go to failure was a great example, things like

that. But when there aren't -- where there are differentiations -- does there exist a differentiation between say maybe a specific gas like San Diego about when they look at what they addressed, what action would be needed for a particular project for transmission compliance and maintenance?

That is if you were to do it, do those scope of criteria -- and I think some of them might be -- some of the criteria might be kind of out there that says we still -- does it need to be protected data?

Does the scope of that criteria between at least the three PTOs significantly diverse at some point? Does what PJ&E look at and the reason they look at it significantly different than how San Diego looks at their systems? And I'm not sure we've really touched on them because I'm going to have a question later on going okay, is there criteria behind those?

And I think there probably are criteria behind it I'm just curious of the application of that criteria even different.

MR. SPEER: Sorry, trying to understand the question.

MR. THOMAS: Understand.

MR. SPEER: Is that between immediate and longer term because you've referenced Q6 but I didn't hear --

MR. THOMAS: I think the immediate we have kind of gotten to. It struck me as we talked earlier about emergency things like that and those struck me in the realm of the immediate. I'm just talking about the long-term.

MR. SPEER: Yeah this is Will Speer. I think it's the driver that determines whether to answer this question it's the driver that determines whether it goes through the ISO process. Is it related to the transmission plan, the expansion, is it economic, is it policy?

The matter and the timeframe, that's what goes to the ISO, that's where the rules are. The asset management piece is you know, kind of everything else we've been touching on so it's really the driver it's not the timeframe that would dictate how you would evaluate and control the project.

MS. CABBELL: And this is Dana Cabbell, and I'm not aware because we haven't really compared notes. I don't know if there is a universal criteria to identify whether its' okay -- a circuit breaker needs to be replaced. I mean there are practices, there are business practices but how we go individually go about it I, you know, we haven't had those conversations coordinated among the PTOs here, upon whether we change out this circuit breaker at this time in this way.

I mean there are common tools and practices that

you know, looking at the health of the equipment and the age and all of that that we've been talking about but the actual way we would change this breaker out at this time, you know, they might be looking at something different just because of the differences in the systems too and the arrangements on the system.

MR. GABBARD: Can I ask a clarifying question? I heard two different answers. The one was do we have consistency in the way we apply criteria within our asset management methodologies and one was do we have a consistent criteria for what projects are submitted to the California ISO in the transmission planning process. Which question are we trying to answer here?

MR. THOMAS: That's a great response, actually. I can answer both -- but let's take a bite of the first one so we're trying to investigate a little bit and when we talk about this to individual PTOs how you look at your asset management and I'm going to try to use your terminology because it's obviously been screwed up throughout the day.

It strikes me as from what I've heard so far today that there might be differentiations in asset management evaluations. I don't want to use the work planning because I might open another rat hole.

And maybe that's just as simple as if that answer is yes then it kind of gets to the heart of it. There is no

one suggesting that they need to conform I'm just curious.

MR. GABBARD: I would venture to take a pass that there's likely a difference in the way that we perform asset management across the three PTOs and the reason why I would take that liberty and yes it's challenging, is that we have systems that are made up of different assets with different conditions, different ages and otherwise and we also have different designs of the topography of our systems are different.

So the resiliency in one section of Edison's grid is going to be drastically different than the resiliency that's built into the PG&E system that again has been pulled together over a hundred years.

But the way that we approach that very finite granular criteria in the way we invest in specific assets will likely be different. But I would argue as you roll that up at the higher level when you talk about asset management principles, I think that the methodologies that we employ across these three PTOs here will actually be consistent with other industries in a lot of instances.

MR. SPEER: And manufacture.

MR. GABBARD: Absolutely, so it really -- the devil is in the details but there's a justification behind it.

MR. THOMAS: That's helpful. I think that does

get to the point. So I would venture if there aren't anything on that to try and move to question 7. I think question 7 talks about is there a process in the CAISO PTOs to evaluate whether transmission related active facility is not initially submitted, should be transitioned into the TPP?

You know, we talked a little bit earlier -- I think it was opened up at the outset, you know, how by way of example I believe it was Edison, was how a project was considered up. I wonder if the three PTOs can talk about their process for when they would consider whether something should be submitted, if you consider it.

So these folks on question 7 I think Edison talked a little bit about that so not to kind of point but to really kind of keep it moving, maybe start on PG&E and go the opposite way.

MR. GABBARD: Sure. I would say there's no documented process other than there is clear documentation of what should go through the CAISO planning processes for a project that would evolve using the NERC compliance example that Edison provided because I can very much relate to that occurring through the evolution of the project.

We believe there's a clear criteria for what goes in the transmission planning process and what doesn't. So if a project were to evolve to the point where it meets the

criteria for going in, then we would submit it through the request window. We would -- time permitting, we would follow the normal process that CAISO does have the ability to off cycle submit proposals if there's some level of urgency behind it.

But in long-term transmission planning normally we have the time to go through the year process for larger projects. I think the one thing I'd like to call out is that while more often than not it will be bright line criteria where we know it's in or it's out. We also have a very good working relationship with the California ISO in that we will consult them if we have a question.

So if there's something that's on the margin for whatever reason and I am talking in hypotheticals, we would reach out to the California ISO and say, "Here's our interpretation of the tariff language based on this unique application that we have not seen on our system to date, and we think it should be treated this way, what is your perspective."

That allows us to be, you know, to rest assured that we are making the right decision in pushing -- in what work goes through the CAISO TPP.

MR. SPEER: Very similar, exactly the same. We work really well with the ISO's too. If there's something on the fence we'll raise a question and we'll ask and we'll

talk through it and decide where is it appropriate to be so.

MR. THOMAS: Is it -- I'll ask a better way, is there a general thought that those opportunities when you ask CAISO about whether something is on the fence we should consider it or not consider it -- is that driven, time delineated like for example is it reactionary knowing what the upcoming unified planning is or is it really this is what we're planning on doing, we might -- it might do this extra down the line or through this part of the system?

What drives that question to hey CAISO, you know, we might have this particular project what do you think?

MR. SPEER: Maybe what it results in right? So if we do see we need a maintenance activity but it is going to result in maybe a rebuild or maybe more capacity or more -- a different configuration, that's what kicks it into that discussion.

It's really what is going to improve the liability or meet some of the NERC standards, are there potential economic benefits? Is there policy benefits? And we don't see those policies so much but maybe economic and reliability.

And it would be too if the plan identifies an area where there's a need like the yearly process and we have a maintenance project that hey, that might meet that need, that's how we would --

MS. CABBELL: Yeah, because I know in PG&E also we have a transmission planning group that we're obligated to do our annual transmission planning assessment under the NERC reliability standards -- you know, the TPL standards.

So we as a utility know where we see some concerns based on our analysis and at that point too then we understand okay, there's some of these maintenance projects happening, especially if they particularly happen on the transmission lines.

Okay, is there something that we can coordinate and collaborate similar to the example that we gave that we saw hey, you know, we can do a little extra capital investment and actually meet an ISO need that was identified in their process and so we put in the request window and go through their process.

MR. MILLAR: And it's Neil here with the ISO. There's one clarification I should probably add that in the ISO transmission planning process and especially on the lower voltage facilities where the time it takes to build certain alternatives might be a bit shorter.

We don't necessarily approve a solution each year for every need we've seen over the entire 10 years. If we see an issue start to emerge 10 years out and it looks like it might either grow or fade on its own due to either changes we'll identify the need, we'll list some proposed

solutions but we won't approve and act on a solution when it could be years before anyone would actually have to take action.

So that information helps the utilities as well looking over their own work to see that well this is already showing up on the radar screen but it hasn't been necessary to take action yet. So that also helps give the opportunity both for the transmission owners as well as other stakeholders to think about possible alternative solutions to those we've already identified.

MR. NELSON: And this does feedback into some of the earlier discussions about prioritization and what happens when. Conditions are constantly changing and when new retirements or something happens on the system, there's now an issue that hasn't been an issue that may have us re-examine what our plans were, is there a way we can, you know, kill two birds with one stone by doing maintenance in that area?

So yes there are criteria and there's you know, a hope that things are going to proceed in a certain way, but flexibility has to be baked into any process to make sure we can react efficiently as conditions change.

MS. SWITZER: Okay, thank you. Well with that it's 5 after 12, we'll break for lunch. We'll meet back at 1:20.

(12:05 p.m. -1:21 p.m. - lunch)

MS. KIZUKA: Welcome back everyone. Before we get started again just as we noted this morning the purpose of this Technical Conference is to explore the questions that were listed in the supplemental notice and not to litigate issues, any ongoing proceeding, even if those proceedings were noticed.

So to that end we ask that you please to the extent possible limit the use of examples on those contested proceedings. If an example from one of those proceedings must be used, please provide appropriate citations for that.

And to the extent a contested example is used we'll provide an even-handed opportunity to respond or you'll have an opportunity to respond in your post-Technical Conference comments. If we do notice that the discussion is starting to become litigation style type of back and forth, we will interject and break up the discussion, thanks.

MS. SWITZER: I think we decided we're going to take questions from the audience first and then we'll jump into the remainder of those questions. So if anyone in the audience has a question just like up at the podium, okay, that's fine too. Okay, that was easy.

Alright we had one follow-up question from this morning. We understand from the discussion that a project would be submitted to CAISO if CAISO had identified it in

the transmission planning.

Edison I think gave the example of the incremental project that they then submitted to CAISO. If there is no identified need what would happen to that project? Would you just not do incremental expansion or you know, or would it be considered like at a later date, maybe just elaborate on what would happen if CAISO didn't identify a need?

MR. MILLAR: It's Neil here with the ISO, I'll take the question. This is issue is actually people propose projects to address reliability needs and we haven't identified a need to begin with -- we actually don't carry forward with the project at all.

We indicate in our transmission plan that we received these submissions but that there was no identified need and we wouldn't advance that discussion that year. Now, if a utility indicated that they thought there was a flaw in our assumptions that led to us not seeing a need, we might revisit it the next year and see if there was something we missed.

But generally, we don't move forward with the issues that don't tie to a --

MS. SWITZER: So if there was a maintenance project that needed to get done timely, you would just go ahead and do that project and leave the CAISO type thing --

if there was no need for it you wouldn't do it?

MS. CABBELL: Correct, and like Neil said, if truly we saw that through our analysis and through our assumptions we really saw a reliability issue we would put it into their process and of course it goes through the process as Neil just described, but if they don't approve it we're not going to go forward with that we're just going to do the maintenance, get that done and then if it's prudent and it makes sense you come back and maybe do that incrementally.

MS. SWITZER: Okay, I think maybe some of us might have heard if a maintenance type project might expand a line but there was no need for it identified by CAISO, then would that be something you would still do?

MS. CABBELL: If it's going to be -- well let's kind of define when you're saying expandable.

MS. SWITZER: Yeah.

MS. CABBELL: We're adding actually capability -- additional throughput in the line. That clearly goes -- would have to go through the ISO process -- our maintenance is not allowing for additional throughput. We're not adding a bigger wire. It might be putting up different kind of wire but then just designing it so that it just meets whatever is in the ISO registry.

MS. SWITZER: But if you were replacing something

at the end of its useful life with new technology it just enhances.

MR. GABBARD: So from the PG&E perspective, you know, we are replacing 1940 infrastructure with current infrastructure so it's not exactly like for like. There could be incidental changes in characteristics but we expect those to be very minor.

The way I interpreted your original question is do you see an opportunity to increase capacity at an incremental cost in the perspective that we have and I think CAISO shares this as if there's no incremental need, you don't have a justification for that incremental cost.

I think that's the approach we'd all take on that situation.

MS. CABBELL: Yeah, and we wouldn't go forward with that incremental cost.

MS. SWITZER: Is that --

MS. TEETER: I think that helps. I think what I was kind of struggling with is I had heard a kind of different formulations of that. The first is that the only reason that something that is going through maintenance activities would go onto the CAISO plan is if it met a CAISO need and I had also heard that the CAISO's transmission planning covers everything that's an expansion of the system, reinforcements.

I think you mentioned changes, kind of the topology of the system, so I think what I was trying to understand is, is there ever an instance where there is a transmission system expansion or significant changes to topology that would result from a maintenance project that didn't go through CAISO?

Say, for example, if CAISO hadn't identified a need and what I'm hearing is CAISO manages all projects that are expansions, that are reinforcement, we'll go through the TPP but those projects only go forward if there's been an identified need for the project.

MR. MILLAR: Right and it's Neil here with the ISO. I think the one clarification I should add is if a maintenance activity is going to create some incidental increased capacity, if there was no need for it, that wouldn't go through the ISO transmission planning process because it wasn't part of an identified -- an ISO identified need.

But by the same token as people are moving to more modern equipment or standardizing their needs for different types of equipment, there may be some incidental capacity increase. Those get reported to us through our transmission register process so we're aware of any increase in capacity.

Now, like I said, those traditionally have been

the case of -- putting it bluntly, you can't buy 1940 vintage equipment anymore. Utilities are standardizing on more modern conductor sizes. They tend to also be standardizing on transformer sizes so that they can do transformer replacements.

So we've seen cases where one transformer had to be replaced though for age and the replacement unit would be of higher capacity and that was because it was a new standard like the standardized size of equipment so that there was sparing in place should the transformer fail.

So we're not saying that our process covers everything that may result in a capacity increase. If it's incidental though to the maintenance activity, we need to be aware of it but that wouldn't automatically cause it to be pulled anymore in the process. It's only if someone's looking at doing something incremental, specifically to increase capacity. That has to go through our process under the terms of our transmission control agreement.

MS. TEETER: That's helpful, so the delineation with respect to an "expansion of the capacity of the system," is really about is that the driver of the project or is it a maintenance project that incidentally increases capacity due to something technology change, whatever the case may be, just availability of different equipment that wasn't available 50-60 years ago.

MR. MILLAN: Right, and in those cases where there is that incidental capacity increase it is the transmission owner's responsibility to defend why that was the right thing to do because we do notice the capacity increases.

Part of my team oh -- next day turnaround on validating any increases in capacity or changes in capacity that appear through the transmission register -- so we do monitor what's happening for other reasons.

And one of our tariff obligations is actually for the utilities to provide information on any changes to the system that occur or reasons for projects that are not approved by the ISO. So we have to be aware of that information.

MS. TEETER: I assume that that's information that's provided to the ISO but not necessarily made public. It's part of the relationship between the transmission owners and the California ISO, is that something that you would post on the website to --

MR. MILLAR: We wouldn't post every change that we've seen. Our models though every year the transmission planning power flow models that include ratings, the models that we use are posted publicly well through the non-disclosure agreement on our website, but that material is available.

MS. TEETER: So the changes are available but maybe not the reasons for which they -- the upgrade occurred?

MR. MILLAR: Correct, we're not reporting that on a day-to-day basis no.

MS. TEETER: Thank you.

MR. THOMAS: If I could ask a question on that. I mean I think as clarification you say if it's incidental then it's up to the PTO's to defend.

MR. GRIESS: Sorry, I guess under the situation where you say that something's changed out, it has an incidental impact to the capacity or something and that would be up to the PTO's to defend -- where would they defend that? What process is there to do that?

MR. MILLAR: I think I'd turn to the utilities to answer that because my understanding is with the FERC revenue requirement and annual -- the requirements as part of the application process.

MR. GRIESS: And then the second question is you say that well you'd be able to see the change in capacity in the power flow model. That may be the case but you wouldn't see a change in bust structure. You wouldn't see a change in type A pole for a type B pole, would you?

MR. MILLAR: Well no, but we were talking about increases in capacity.

MR. GRIESS: Right.

MR. MILLAR: Now the change in configuration would show up in our analysis of various contingencies that includes the breaker analysis and so forth that you would see the results in our need analysis that there's been a change in configuration.

MR. GRIESS: A little more difficult to find though.

MR. MILLAR: Well, to be clear our planning process is to move forward with the information that's already there. We're not providing a reporting system on the utility's maintenance activities.

But like I said we do monitor and see the changes in configuration and ratings as they're reported through our transmission register. These also need to be built into our network model for dispatching the power system.

MS. SWITZER: Okay, well alright thank you. We're going to move onto question 8. What information does CAISO -- does each CAISO PTO submit to CAISO during phase 1 of the TPP concerning these maintenance compliance activities? We've covered this a little bit but -- and we'll start with --

MR. SPEER: Will Speer, SDG&E. We had nothing. Nothing that could be related to phase 1. Phase 1 we talked about earlier that's a model to study parameters that the

ISO is going to do for the upcoming planning cycle.

MS. CABBELL: Yeah, similar.

MR. GABBARD: Maybe I'm misinterpreting the question. I don't know that I would agree with that. I think I would agree with what Neil just mentioned that we provide updated base cases, updated power flow models, we on a real time basis, update the transmission register as well as the CAISO RIMS, so all of that information is provided either in real time or in phase 1.

Any of those projects that ultimately would be meeting a need as we previously defined that would be under the jurisdiction of the CAISO TPP would have a series of additional deliverables that would be submitted with it as a project but that would be in the later phase of the TPP.

MR. SPEER: I'll agree, we do provide updated base cases if it does have changes so.

MS. CABBELL: Yeah, absolutely, I just understood the question though specifically talking about these maintenance related projects and whether they go into this phase 1, that's how I interpreted it.

MS. TEETER: So they go into phase 1 -- I'm sorry this is Valerie Teeter with FERC staff. So they go into phase 1 to the extent that they change the base case. They change kind of the system configuration that CAISO uses in its planning process, okay.

MR. SPEER: Yes.

MS. CABBELL: If that -- something like that did occur.

MS. TEETER: To the extent that's the case.

MS. SWITZER: Okay, I'm going to skip number 9, we feel like we've covered that. So number 10 I guess this question would be, you know, in advance of rate cases -- are there any processes for stakeholders to review -- we have a question, sorry?

MS. LOOKER: This is just a question, this is Geneva Looker. I'm not sure it follows up exactly but let's say that as loads are changing in California and you know with all the solar generation and distributed generation coming online, things are shifting and so a utility might not need to replace something if it's no longer necessary to serve loads.

Let's say a manufacturer goes out of business or something and it's no longer there. Would that kind of information get shared with the CAISO if you're -- I mean --

MS. SPEER: That's part of a -- this is Will Speer, SDG&E, part of a load forecast that we work on with the ISO. In most of those cases that's distribution connected in most cases so it would just blow up and aggregate to a substation. We wouldn't report that manufacturing business but we might say our load at this bus

is lower. That would be considered when they do their power flow studies.

MS. LOOKER: And would you consider that let's say when you're deciding whether or not to replace a line or replace some piece of equipment? Would you be looking at the usage and whether the usage is still needed?

MR. GABBARD: Let me clarify a little bit so we're all talking on the same page. We, PG&E have idle facility programs to look at whether or not facilities are still needed and then even having an idle facility creates risk and exposure for the public so we have a process for retiring assets that are no longer needed.

Usually that is more of a radial fed piece of infrastructure to serve a load that no longer is needed. When we talk about the scope of what we're talking about here today -- we're talking about the network transmission infrastructure.

And the nature of the transmission planning that's done under the CAISO process for the network grid is very deterministic looking at set criteria laid out in their TPL et cetera that are looking at very low probability events of N minus 1 minus 1, et cetera where in order to unravel we have to say we could take this piece of -- this liner element out of the grid.

We would have to unravel -- we'd have to reverse

engineer the entire TPP in the other direction which would likely not be fruitful because the grid is operated in a way that they actually leverage that redundancy in order to be able to meet NERC planning criteria.

And at present we are still finding needs to increase that resiliency not decrease the resiliency.

MS. BONE: Yeah, I just wanted to do a little follow-up on question 8 and that I'm wondering for each one of the IOU's -- PTO's, if you could respond. Are all of your maintenance practices on file with the CAISO so that if we see these confidential maintenance practices we'll see the universe of how you engage in your maintenance?

And the additional question is do those practice documents show the criteria that you are applying to determine how to prioritize your maintenance? So maybe we'll start with Edison?

MS. CABBELL: I do not know how deep the documentation is. I'd have to go back and see what we actually do provide to the ISO related to your question.

MR. SPEER: Yeah, I would agree. We provide a lot of the stuff that they audit we provide all the information needed so are we doing our annual inspections -- those type of things.

As far as our criteria for equipment replacement I don't think that's viable.

MS. BONE: Wouldn't you go that deep? Wouldn't you consider that part of the maintenance practice?

MR. MILLAR: As I said the Appendix C of the transmission control agreements sets up all the reasons, all the issues that do need to be addressed and then they can process this information that's provided to the ISO.

Whether or not there are other requirements beyond that I don't know and I'd have to go back and revisit the documentation with the PTO's myself to doctor an opinion on that.

MS. BONE: And specifically with regard to PG&E would we see in those Appendix D -- C documents, the strategy documents and the standards that we've seen in the TO 18 rate case? Would those be the types of things?

MR. GABBARD: I do not know what's included in those maintenance plans, I'm not familiar with the specific plans. I do know we have plans on file to meet the requirements under the CAISO tariff. I don't know the makeup of that content.

MS. BONE: Do you all expect for those plans that are on file with the CAISO to be current or could they be dated and you're doing different things now?

MR. GABBARD: I would expect them to be current.

MS. BONE: Thank you.

MS. SWITZER: Question 10?

MR. SPEER: So I think, Will Speer, SDG&E. I think we discussed a lot about the rate cases filings that FERC already signed off and we did beat them up. But the only thing we haven't touched on which I'd like to bring up that is during our filing we actually had the CPUC bring in an independent engineer, that was part of a rate case filing agreement with FERC that actually comes in and audits all of our projects.

And there was a back and forth, from the site, IS data requests so as far as another level of what's public and an opportunity to bite at that -- whatever you want to call it, another show of transparency we do have that performed every year.

I'm not sure what the other agreements are but at least we host that independent engineer that's, you know, chosen mutually between the two groups, and they do an audit -- all of our projects that are in that PO filing, but I'm not aware of any other public process.

MS. BONE: And just to be clear that that provision is pursuant to a settlement, it's not compulsory so they'll be filing a new rate case at the end of this year and that provision may not survive.

MR. THOMAS: And just to be clear if you don't mind, Will just to follow-up on that. When you say all projects that are in your TO rate case we're talking about

transmission and maintenance type projects?

MR. SPEER: Everything.

MR. THOMAS: Okay, thank you.

MR. NELSON: If I could I'll talk in history because it's not live. Historically we had had a similar type of capital review process within our FERC rate, the same type of -- even provided funding to fund an engineer for the PUC or engineers in the case to dig into all of these sorts of capital spending and other issues.

And as they say we now have a new process in our tariff we think is more robust, provides even more of a timeframe of transparency and open to a larger group of stakeholders that say it's been approved but suspended.

MR. HADDAD: I think you're talking about the TMCR?

MR. NELSON: Yes I am, sorry.

MS. BONE: So, Traci Bone from the CPUC, Jeffrey I'm curious whether you think that your proposal complies with all of the requirements of Order 890?

MR. THOMAS: I don't know if I want to get to that question today. I know we've referenced it and the Commission has already adjudicated it. I think we want to staff off and focus on the questions here if we could.

MS. BONE: Fair enough.

MS. SWITZER: Questions 11 and 12 are kind of

related so maybe we'll just kind of answer them both at the same time.

MR. THOMAS: Hold on, Bryan was there a question, I'm sorry.

MR. GRIESS: I didn't hear all three answer the question 10.

MR. GABBARD: So I'll let them to say whether they did or didn't. So PG&E specific to question 10 we do not have a process to fund an independent engineer to review our portfolio. We have provided in discovery through our TO rate case every project authorization justification strategy standard procedure you could imagine.

So our books are wide open through that process but we do not have a separate independent evaluative process to supplement.

MS. SWITZER: I think I may have mentioned earlier to about a five year forecast concluded in these rate cases. I was just wondering what that forecast includes. Is it just a dollar amount, it is actual products, activities?

MR. GABBARD: It's by project. It's a list of information about any project that is within our expenditure for the test year. It gives the total expected costs and the in-service date for that project so while it may not be placed in service in the test year and therefore be a

capital addition in the as-filed revenue requirement, it is still included in our filing as a list of our portfolio that is incurring capital expenditures for that time period.

MS. SWITZER: And if a stakeholder saw that and had questions or comments on that is there a way -- how would they go about that with you? Is it just information for them?

MR. GABBARD: Well the first step would be to ask questions through discovery absolutely. There's a caveat -- the granularity for which we go through that forecast is going to get only projects one million dollars and above.

The smaller higher volume work is bundled together.

MR. THOMAS: But just for clarification solar energy understood and we understand the responses is that process is really in your rate case process -- discovery in the rate case process that is I'd have to ask you, you know, some interrogatories about what's the dollar amount, where does it come from, what was the plan, so on and so forth, is that accurate?

MR. GABBARD: Can you repeat that last part?

MR. THOMAS: The discovery would phase that out, the dollar amounts, the process you determine the use, so on and so forth. That will all come from discovery in your rate cases?

MR. GABBARD: That's correct.

MR. THOMAS: Thank you.

MR. NELSON: I'd like to expand just a little more. In addition to the TMCR we do have an annual process where we post a draft of our rate every mid-June, by June 15th and we don't actually file that rate with FERC until our deadline is around December 1st. So we have this window four and a half, five months, where we put it out there that allows for a lot of opportunity, back and forth. It's not a compressed time.

There's plenty of time for data requests, replies, questions on the replies, and historically -- historically, we've not seen protests by the time that the December 1st actually filing roles along.

So our current structure maintains that. We still have that window and in addition we're putting on the TMCR to really cover years 1 through 5 through one of these processes of these types of asset management activities as well as everything else in the rate case.

MR. HADDAD: When you say historically is that historically through the settlement agreement?

MR. NELSON: Yes

MR. HADDAD: That's now been superseded. Yes, the settlement agreement set forth kind of the timelines on that process.

MR. NELSON: Yes, so stop me because we have an active rate case in front of you but that active rate case has proposed the same timelines where we'll be posting and along this data request period and the same filings.

The proposal doesn't have the paying for the consultants that we did in a previous settlement but people can still ask the questions.

MR. THOMAS: Katherine you had your question up first.

MS. MAPES: Thank you, question 10 asks specifically whether there are processes for stakeholders to provide input on transmission related maintenancing appliance activities and I think the answer to that is an unqualified no. There are opportunities as people have pointed out to ask discovery questions and there are opportunities based on the results of those discoveries to assess whether the rates are just and reasonable that result from these projects but there is not an opportunity to provide input to the company and I think that's a major point that's lacking here -- we just simply haven't had that opportunity.

MR. NELSON: I would know if TMCR's specifically designed to get input all the way through five years forward so it's -- you're seeking, we're actively seeking input in that process and it is a new process. We haven't run it

through yet, it actually seeks input.

MR. THOMAS: Was there any follow-up data specific?

MS. MAPES: No, and I think the TMCR we've discussed that we think it should provide more opportunities for input but we appreciate that there for the first time will be that opportunity.

MR. THOMAS: Geneva, I think you had your card up next?

MS. LOOKER: This is Geneva Looker and I just have a couple of comments and questions. One of them is that when Dave was talking about the five year plan that they have and that they provide in their TO filings, I would note that it is not the complete five year plan and it only contains projects that will have expenditures within the two year forecast that is there.

So that does not allow intervenors to look ahead at projects that might be two or three years down the road, that they're planning to do, but they don't expect to expend funds on them yet which then again brings up the problem of by the time that they're in the TO filing, they're already "in flight" or they're already in progress, they're already in development and so that they won't -- they don't want to have objections to them.

You know it's like they're already in here,

they're planned, they are going forward. Your input is not welcome at this point -- so that's number one.

Number two -- Edison, when you were talking about having this process of five months or so historically and I have not been a part of your process at all but was that -- you know normally when you have a TO filing and you make a filing the discovery process doesn't start until FERC has issued an order and set it either for hearing or for settlement negotiations or something like that.

And so and often until that occurs and the ALJ has gotten together with the parties and said okay, now we're either going to hearing or we're going to go to settlement process so now you can start discovery. That really limits the time period of you know, five months if you file in June and it is effective in December. Well some of that isn't going to take place.

So it's just -- it's pointing out that the length of time that might allow for some of this interaction has not been really much time at all and the TMCR or whatever, would improve on that for sure.

MR. NELSON: And I may have misspoken with my technical terms. Just to clarify the record we post our draft write out in mid-June and then we allow data requests. And I may have misspoken for discovery, but we allow data requests. And that data request process continues all the

way through until I think through November and then I think you're right -- if we did not, if we had an issue where we were going to settlement I think technically we don't go to discovery until we're in settlement.

The data request process has a multi-month riser, I have an account here.

MR. CHEN: So this is Gary Chen, Edison. I think you guys have a misunderstanding. We don't file a stated rate every year like the formal way has already been approved, well the previous one. And so it's the -- data request process is not capable of by a FERC order -- protocol.

MR. NELSON: Yeah, just the annual update that allows responses to --

MS. LOOKER: So it is in your protocol?

MR. NELSON: Yes it is.

MS. LOOKER: Thank you.

MR. NELSON: Calendar around it, I sure do.

MS. SWITZER: Alright 11 and 12 are covered, we talked some about reliability type maintenance projects but -- is it all new projects that depresses PTO -- I'm sorry, depresses TPP process? Are there some NERC projects would fall on the maintenance asset management category?

MR. GABBARD: To be direct, it's the latter and so I think Willy, correct me if I misspeak but the subset of

the NERC standards that go through the TPP would be the NERC TPL requirements. There are a variety of other NERC requirements that some of which I think the TPP is anchored on the TPL, so we'll leave at that.

MR. THOMAS: For clarity, could TPL is the acronym for?

MS. CABBELL: For transmission planning.

MR. THOMAS: Just two words, three letters two words, okay, I just wanted to make sure.

MR. GABBARD: Based on the fact that transmission planning has a T, and a P and an L. But it really is NERC's standard is TPL. Nuke would be NUC so they try and make it align but it truly, it's not a utility acronym, it's TPL.

MR. THOMAS: There was no judgement, trust me I'm down here.

MR. GABBARD: Basically it's NERC, very good, thanks.

MR. MILLAR: But we should be clear, Neil Millar with the ISO, there are other NERC standards that relate to equipment, relate to cyber requirements that are CIP dash and then the suite standard there.

So when we are talking about the NERC standards that drive reliability projects in our planning process, we're referring primarily to the TPL suite as well as some of the others that are involved in rating system operating

limits for the system and the new -- some of the nuclear requirements around adequate infrastructure around nuclear power plants.

So there are others that now apply to the planning process beyond just the TPL but the TPL's suites of standards are the bulk of the ones that apply in our planning process.

MS. SWITZER: I think that's what we were trying to get at because we know that the TPP has a reliability bucket, a policy bucket and an -- I cannot touch bucket. I'm just trying to understand the reliability bucket and what goes in and what is the system.

MS. LOOKER: This is Geneva Looker again and I could be wrong but at least for PG&E that one of their buckets or whatever, the major work categories that they have is called reliability and some of those, you know, they are all part of the repair and replacement facilities. Not all of them are NERC compliance are they -- NWC 93 or 4?

MR. GABBARD: No, our NERC TPL they're the projects that go through the CAISO TPP.

MS. LOOKER: Right, but I'm talking about the ones in MWC 93 or 94 which is labelled reliability and I don't think all of them are actually in response to all of the other NERC requirements like the LIDAR or like the CIP right?

MS. AMES: You're asking if there's a one for one correlation between every item listed in the reliability list to a NERC requirement?

MS. LOOKER: That is the question. I mean for instance I think this is all public, no this one isn't.

MR. GABBARD: I would say the answer to that is no, I do not -- please correct me if I'm misspeaking. I do not believe there is any discreet NERC standard that says we have to replace aging infrastructure you know.

We do have broader releasing obligations from the CPUC and otherwise that say we need to rely -- we need to operate or we need to manage our transmission system in a safe and reliable way and the requirement there is to employ -- prudently employ good utility practices.

That's where we leverage industry standards, industry benchmark and engineering judgment in order to take the actions necessary to maintain safety and reliability.

MS. LOOKER: Okay, I'm just looking at some of these projects and some of them are like bus sectionalization or converting a bus or SCATA projects or install switches, or bussed reliability improvements.

So there are these projects listed that are forward reliability. They don't say they're for NERC standards, but they're under the repair and replacement process that we have no transparency on, at least prior to

implementing -- being in the TO filing.

MR. THOMAS: And so if I can just follow-up on that real quick Geneva, I apologize, and coming down to a caveat from counsel after the break. I just want to be sure. Is your question looking at -- do everything they do for TPP purposes is only WEC or NERC related or are there other things that aren't and do they follow the same process?

MS. LOOKER: No, no, I'm just trying to point out that they are claiming that some of their repair and replacement projects are for reliability but they are not for reliability needs as defined by the TPL, by the NERC TPL standards.

MR. GABBARD: That is correct, so let me clarify on that. So the NERC TPL requirements as I stated earlier are very deterministic and they say you shall not have -- be exposed, shall not have these types of consequences for these types of contingency events.

So there's no probabilistic assessment in that, it should never happen regardless of you know, how low the likelihood is. When we talk about reliability on our asset management related projects, it's more on the traditional reliability sense -- it's about maintaining service to our customers.

So for example we may have a line that's nearing

the age of its -- the -- nearing the end of its useful life. And we've actually had the line fail a couple of times but we put together with slices and at some point it's got 6, 7, slices.

And we get to the point where we say this -- we have record on this line that this conductor is at the end of its useful life. It's failing, it's falling out of the sky, we need to go out and proactively replace that. We will perform a like for like replacement.

How we characterize it internally is it's a reliability driven project because we don't want it to continue to fall out of the sky and there's new service to our customers, but it's not to meet TPL.

MS. SWITZER: There's no NERC requirement but you still consider reliability because it's still reliability operating?

MR. GABBARD: Absolutely.

MS. TABA: Are there other -- this is Monica with FERC staff. Are there other NERC reliability standards that might play -- for example, for maintenance or the facility standards, do those apply to your TO's -- transmission owners or operators?

MR. GABBARD: There's a host of standards that apply.

MS. TABA: Okay.

MR. GABBARD: But in this case these examples that work on reliability are not scared driver is not the NERC reliability standards, but nearly everything we do around compliance and maintenance improves reliability.

You're taking a piece of equipment that's four years old so I think we just need to be careful on the reliability, how we define it. So there's a NERC planning standards that drive that set of reliability -- that's the ISO. Then there's reliability by replacing old equipment -- just increasing the reliability of your system.

But there is -- and there's hundreds of NERC standards so I mean there's ways to -- we're responsible for a lot of them and we do have an agreement in place and all of us -- each of us do with the ISO and who's responsible for what.

And you know, TPL's the operator, the operator for the grid, they're responsible for those, so that's all clearly defined in the agreements.

MR. MILLAR: It's Neil here with the ISO. The other thing I'd add is that we were also trying to avoid getting tripped up around the use of the work reliability and the context of reliability driven projects for transmission and planning purposes versus these other types.

So we've generally inside the ISO market completely referred to these types of programs as improving

or maintaining the availability of the equipment and then there's the transmission planning side making sure that both pieces assuming that they're properly maintained and available, will work together to provide reliable service.

So you know, I feel like it's really easy and we try to be careful ourselves about not getting tripped up between I'll say the more defined use of the word reliability as in reliability-driven transmission projects in our transmission plan versus the more general use of the word reliable that, you know, a properly maintained system will be more reliable than one that isn't.

So there is a terminology issue there that's tough to manage.

MS. BONE: So in moving forward it seems like one of the things that we'd want to do as part of the tariff process is to have a unified planning assumptions document that would reflect the best industry standards and other criteria that the utilities are currently using or that they propose to use going forward for their maintenance practices.

And I appreciate that maintenance would be different than transmission planning in that circumstance. So I'm curious do you have those types of documents? Are your criteria and your best industry standards that you're following in making decisions on, are they written down and

could we bring them together to try to develop some kind of a unified planning assumptions document, start with Edison?

MS. CABBELL: Yes, they're written down. We have them documented internally. Whether we create this unified planning assumption document that's something I think that would need some further discussion and try to understand exactly all that's going to go in there, what it would look like. I think that takes more discussion on whether that's a direction we want to go.

MR. SPEER: And even unified, even we talked about earlier we have different systems, different equipment, different manufacturers -- those drive a lot of requirements for replacing aging infrastructure so.

We do have documents to the list, our criteria -- one we would replace aging infrastructure and how we prioritize it. We haven't made it public yet, but you know, that's -- it would be a pretty large document -- a pretty tall task to try to put all the maintenance replacement.

I don't know of any utility anywhere or any plan that's out there that discusses this comprehensive plan. So we'd have to think about the scope of what we're actually trying to accomplish but that's --

MR. GABBARD: So I'm not sure I completely understand what's being referenced as a unified planning assumption or unified planning assumptions referencing the

CAISO transmission planning process.

As we've stated many times, we don't do transmission planning on our own, we go through the CAISO process. If you're alluding to some sort of document that characterizes the overall objectives that translate to the strategy and the pace at which we invest in our aging infrastructure, there would need to be a document that says a utility in the State of California shall not have say 80 minutes greater than "X".

Or should not have a piece of equipment that has gone beyond this number of years in service, and I think that would be very challenging to do and if I'm misunderstanding then maybe a clarification of what it is that you're envisioning for this document might help me understand what it would take for us.

MS. SWITZER: Well I think question 15 kind of gets into solutions so if it's okay to table this. We'll set aside some time to talk about that a little bit. I just wanted to make sure that everyone was clear on the reliability questions. Does anyone have any follow-up 11 and 12?

MS. BONE: Just to clarify that my question goes to reliability as defined by the utilities and therefore what standards and criteria they are applying to do that work.

MS. SWITZER: Alright, I think we'll move on to questions 13 and 14, some more -- question 14 just a question of the PTO's if you could answer for us. How are you determining what gets capitalized versus what goes in L&M?

MR. NELSON: Well generally there are accounting rules that determine this and just conceptually if you're doing a new thing, a transformer being mounted somewhere is viewed as a capital project and the work that goes into designing that engineering construction of the facilities themselves are capitalized.

There's also some A&G and some other adders throughout the company because there are assumptions that other people besides just the engineers are contributing to building this thing. It's capitalized or a portion of it.

And then conceptually, once it's in service the ongoing keeping it going is typically maintenance. It's typically not capitalized. Now there can be exceptions to the rules with piece of equipment that have longer lives or shorter lives and then specific accounting rules will kick in on whether those pieces of replacement parts are capitalized or considered maintenance.

MS. SWITZER: A little background on the question I guess is this -- is that we heard in the record that if these are maintenance and compliance activities, maintenance

being the key word, why isn't it going into the L&M bucket, so that's kind of why we're asking the question.

MR. NELSON: So, well I mean transformer replacement is a classic example. We are keeping the machine running. We're not changing the machine. We're keeping it going and the transformer needs to be replaced so to that degree we're maintaining the system, we're maintaining availability but as we've talked about there's some engineering, there's some work, there's some things that have to go into that transformer replacement so it's a capital project.

So it is maintenance -- it's maintaining the grid, but rate making its capitalized.

MR. SPEERS: Right, I mean I don't know how deep you want to go into this but there are rules around what gets capitalized and what doesn't. You know replacement of a full unit is usually capitalizing it. Anything working on that unit is maintenance even though we consider it, we call it compliance and maintenance. I mean it's exactly what he said.

If I'm replacing a breaker, that's a capital. And that's the accounting rules behind it and we all have groups that decide on whether it's capital or L&M, so.

MR. GABBARD: Yeah, I agree, I'll provide a little additional clarity. You know, capital accounting is

completely separate from the utility operation. It applies to all different industries and there are different accounting rules that can be put in place, you know, in some industries it could be extensive of life or translate to capital, but that doesn't apply at least for PG&E.

PG&E has a unit of property structure or retirement unit. We have set guidelines, there are some quirky nuances, I think chairs have different criteria, tools have different criteria, but in general if the material costs associated with the investment in the new unit of property -- if the material costs are greater than $500.00, and the expected life is greater than a year, that is considered a retirement unit.

The installation of a new retirement unit constitutes capitalization. Maintenance on or modification to an existing retirement unit is expense and that's pure financial accounting rules. I think some of the confusion comes out in the ongoing O&M, operating and maintenance costs that we incur at our expense are a lot of times called maintenance expense -- that's what we defaulted to calling that maintenance.

And so the use of maintenance in this context which is really more the asset management investment planning that we do we're kind of blending those two together but they are sole and separate and if we were

installing a new unit of property that has a material cost greater than $500 and expected useful life greater than a year, that should be treated as capital and depreciated over the expected use of life with a rate of return applied to that bulk value over time.

MS. SWITZER: Okay, thank you. Question 15, we've obviously been hearing calls for greater transparency around these maintenance projects, we'll hear from this side of the table first about your thoughts and then we're planning to allow enough time for the PTOs to talk about any concerns they have around the solutions, okay.

MR. THOMAS: Can I take a pause -- it seems there's a question of whether we -- we were just talking about question 14, we had viewed question 13 and 14 very similar. If there's questions on those you guys would like to raise we'd be happy to hear them but we view the construct of the question on cost and transmission rates are reflected in wholesale rates,
viz a viz, how they determine whether they're expensed or capitalized.

In some respects, for purposes of this Conference which are rather self-evident, it's either an expensed item, how it goes into rates is an issue that would be subject to that rate case and whether it's, you know, we talked earlier today, prudent or non-product, stuff like that.

Similarly as a capital asset into rate base matters, so we just kind of combine those but if there are questions on that we certainly don't want to preclude anybody from asking a question.

MR. GRIESS: I think question 13 is that just rates?

MR. DOCKHAM: Thank you, so I just wanted to let Laura and Linda know what I'm going to say here. I've checked with Marc to make sure I'm okay, so Marc you jump in if I veer from what we have previously discussed.

I think through discovery and the TO proceedings and the knowledge that we've gained through the last several years in those proceedings, PG&E has provided a lot of information on their processes which has helped us to understand much better some of the thinking that underlies their practices.

I'd say we're still on the upward portion of the learning curve to understand how they are being applied in every instance but I do think that they provide the framework for a starting point in a planning process that could be or form the basis for this unified planning assumption document that we've been referring to all day.

You know when I think about some of the things we've seen and you know, in terms of the ISO's performance based criteria, I wouldn't go so far as to you know, the

criteria that Dave was speaking to where we're going to have a minimum or a maximum SADI or safety number that is adhered to without regard to cost, but I would suggest that, you know, things like the worst performing circuit criteria -- and when those things are evaluated and there's a plan put in place to develop projects over the next five years, that we understand the metrics and how those worst performing circuits are identified.

And as I started out this morning, indicating where the municipal entities count one customer, I'd like it very clearly identified in those planning processes that we're going to include all customers in that metric and it's not just PG&E, but it's PG&E and all the municipal customers that reside behind that meter, because that's who's being effected in an outage.

And I understand PG&E may have some reporting criteria for CPUC purposes that are different than the reporting that we would like to see and in this worst performing circuit criteria, but nevertheless the ability is there to separate that kind of information out for different purposes.

And with that I do think, you know, that the information provided provides a great framework and I also believe that much like the CAL ISO's process where it has evolved over time and it has improved over time, that

whatever is put in place here is going to need to be continuously reviewed and continuously updated, particularly as we just start because it's a new endeavor for all of us, but it's something that I think needs to start right away just based on the magnitude of the projects that are in place and ready to be put into service.

MS. BONE: I'll just add that we do have a draft document for a planning process, and, but it hasn't been reviewed in many months since a number of your orders have come out and so we'd like to take it back and think through it a little bit more and then we'd be ready to share it with the parties to move the ball along.

And it would include the development of a unified planning document, planning assumptions document. And I guess what we'd be looking for is quick movement to get the utilities standards and criteria, you know, what they define as needed for reliability, how they make those determinations about what is good and best engineering practices.

Because those are the kinds of things, I think, that we'd want to include in this document so that would be kind of immediate first steps.

MR. THOMAS: No, I was just wondering -- I was going to potentially ask some follow-ups on what that might look like but since you know, I don't know if there was a

greater framework you can paint a picture for us at the Commission with kind of, what might be in it just to get a feel for, you know, what thought processes might be there.

MS. MAPES: Sure, I think I can talk about that a little. I think we've started with the unified planning assumptions document because we believe that getting the assumptions underlying the types of studies and analyses the PTOs are doing is important to us to have a basic understanding of what's going on in the planning process.

So our concept would be that that unified planning assumptions document would be released each year. There would be a stakeholder meeting to discuss it and then there would be comments on following up after that stakeholder meeting -- a formal opportunity for comments.

And following on that there would become a draft transmission plan which would start identifying the specific system needs and that would take into account all the studies that were done and the assumptions that run the unified planning assumptions and then there would be another stakeholder meeting to discuss that and an opportunity for stakeholders to start proposing their own solutions at that point, so that would be the second of what we envisioned as three stakeholder meetings.

And then the draft transmission plan itself would come out and that would provide proposed solutions. And

this, so there would be the third stakeholder meeting. So we're envisioning an iterative process where we really do have a free flowing exchange of information between the stakeholders and the PTOs.

We're -- as I think I said earlier, we're not looking to dictate the results of the process but we think if we can have input into every stage of it we will ultimately be better positioned to participate in a meaningful way in the planning process.

MR. JACKSON: Excuse me, Franklin Jackson, from OMR. I'm just wondering how you feel that some of these immediate we need it projects were factored into that framework you just outlined?

MS. MAPES: I think we understand and to be honest we haven't addressed that in our draft tariff language. I think we understand that there will be projects that will not go into this plan because they have to be done immediately and it's a five year plan.

We understand that there are projects that don't take five years to plan and implement so there will be some new projects added each year and there will be some projects that just have to be done in the field.

But what we're really looking for is what we think is the bulk of the currently self-approved projects is the things that are planned on a several year basis which we

can't look at from year to year and say this is how this is developing from year four to year five, this is how this is developing from year three to year four.

MR. THOMAS: And Katie, as part of your takeaway with that, as you go back and isolate them on to assert that you have it all thought out maybe at this juncture, but we heard a little bit about those documents or those commanding words that set up some of the activities that they do for to use your words, self-approved projects, could be quite voluminous.

How would that concept of creating a unified planning encapsulate that without being overly burdensome or overly narrow but yet to be seeking on what you give is transparent? Is there a thought on that yet?

MS. MAPES: I think there's a couple of thoughts -- I mean I think that the first is that everybody that has been participating in this process is expecting that we'll have to have engineers and transmission planners review these documents.

We're expecting them to be voluminous and we're expecting it to take a good deal of work on our part to really dig in. I think we understand that there is a level which it might simply be too much to ask to be provided, but based on what we've seen so far, and the discovery that we've gotten, we don't think we've reached that level, we

think that the documents that have been provided can be the basis for a solid plan.

MR. THOMAS: Okay, thanks.

MR. PRICE: This is Greg Price, I'm in the Policy Office. Is it possible instead of having a unified document to have a single document from each TO outlining all of their criteria just so that it would maybe not be so difficult to consolidate practices?

MS. MAPES: You know I think that's what we had been thinking would likely happen. We've been using unified to refer to what each TO comes up with, we'd assume that there would be separate documents.

MS. LOOKER: This is Geneva Looker. And to your question about the voluminous documents and what we're looking for, I think based upon the information that we have seen and that some of the parties have discussed. You know, what we're most -- well what I'm most interested in are things like, okay, when we're looking to replace a circuit breaker, these are the three or four or five elements that we look at -- age, condition, manufacturer, whatever.

And every utility might have a different criteria and then they get weighted. And then what we would like to see is, you know, that would be part of the initial -- these are the assumptions, these are the criteria.

And then the next phase would be okay, we ran our

study and we looked at all the circuit breakers, our transmission level circuit breakers and this is the list, these are the ones that look to be in the most need of repair.

And then, you know, presumably those ones who most need the work will then be what our proposed as final solutions, you know, so that we can see that the prioritization is taking place -- that the prioritization makes sense.

If something seems out of place we can ask those questions and they can explain -- oh, well we have these other projects going on right now, you know, so we're going to do it at the same time. Fine, you know, but it gives us that ability to ask questions, pursue -- get information.

And that is -- you know and I think over time, initially that might be difficult for some of the utilities if they don't have records, you know, in a fashion that they can do this easily, but I think over time this is probably going to smooth itself out, probably just like the TPP has over time is that you become used to it and you know what you're doing and you know what's expected and the process moves along.

MS. AMES: This is Angela from FERC. So I'm hearing two pieces to this and please confirm. There is both a window into what is happening but also an opportunity

to opine and redirect if you disagree? Right, so it's not just about transparency it's also about modifying behaviors with which you disagree, is that correct?

MS. LOOKER: I believe so yes, that there is a -- that's the point of having some dispute resolution if necessary. If we sit there and see that they're doing a whole bunch of replacement of projects that according to their prioritization list don't seem to be needed immediately, that we could question that and say why are you going -- why are you doing this, or why are you trying to do this in two years rather than eight years, or you know, that kind of a feedback at least.

And so yeah, that's actually the next piece too of thinking about as these conversations are developing, as you all are collaborating to figure out what might work, how the timing fits in because a report posted on a website that doesn't have that dialogue element is probably easier and faster to implement than a more robust dialogue.

And so making sure -- and I shouldn't even use robust, then a report that it's posted is probably faster to implement than a conversation and redirection of activity right?

MS. LOOKER: Yes, but I think the Order 890 process asks or tells, requires utilities to provide transparency and to provide the ability for customers to

participate and to be a part of the planning process and that is what we are asking for.

MS. MAPES: And I would add on the timing that I think that we might need some sort of abbreviated process that we'll have to discuss in the first year or two because these projects are, you know, about to go eminently into service and they're happening now and there's not necessarily time for a full process. But once we have a process up and running, we can from year to year know that we'll in March we do the unified planning assumptions and in September we do the draft transmission plan.

And we'll have a system in place and I think everybody will be able to keep moving along that track pretty easily once we have a system up and running.

MR. MILLAR: Thank you it's Neil here with the ISO. I keep vacillating between being concerned, relieved -- , I'm undecided I just have to leave the card up even as I go through the oscillations.

Just to back up, the ISO prepares each year a document called the unified planning assumptions and study plan. That's the phase one of our annual transmission planning process, it details the assumptions we're going to be using, all the background information, the material we'll be turning to and it's the study plan that we then, after we get that approved, embark on the actual analysis each year

and we produce an annual transmission plan.

Now I'm hearing the same words being used as a unified assumptions document plan and it's not always clear to me if the intent is to -- and we're flattered if it is to copy, emulate some of the current ISO transmission planning process and apply it to the maintenance activities with the utilities, or if the intention is actually to get some of this incorporated into the ISO's transmission planning process.

And I do need to be clear that that's not a minor procedural issue. Shifting responsibility for the maintenance activities into an ISO process with ISO responsibility to approve as we do with transmission projects, is a major shift to current roles, responsibilities, it could affect huge amounts of staffing, liability issues. It's not a minor process difference between the two.

So when I'm relieved is when it sounds like this is an issue around transparency for the individual and utilities, transmission owners to address with the complainants on the transparency around their capital maintenance.

When it shifts to the terminology sounding like it's being incorporated into the ISO process that's suddenly a much different discussion that requires a much broader

range of issues being debated and that's where we get very concerned.

So it almost -- it would help me out if we were using different terminology than the words specifically extracted out of the ISO process or maybe it's just the clarity we need if are we talking about a separate process between the complainants and each transmission owner or are we still talking about possibly trying to labor this into the annual ISO transmission planning process which is, like I said, a much different conversation.

MS. MAPES: So I think that we've always been open to both ways, we've always seen advantages to putting it under the ISO process, but we understand there are a number of hurdles to doing that and that it would require as you say, these large shifts.

So the working assumption we've been working under is that these would be individual processes run by the ISO or run by the PTOs and we've developed a -- we've been using some of the same terminology because we think some of these things have worked well in the ISO and are good things to emulate.

MR. MILLAR: Thank you.

MR. HADDAD: This is Mike Haddad, FERC staff. I had one question -- I may have misheard and that's been kind of a couple of hours ago, but I have heard that there is

going to be some consistency in the timelines between your proposed approached and ISO's TPP and I thought what I heard was that there might be like off-ramps if necessary.

So just following up on Neil's point, is there an expectation that some of these -- some of the projects will be discovered through this process as being oh this is really a capacity addition -- I really shouldn't go through this. And again, I might be misheard.

MS. MAPES: No I don't think you misheard. I think we were thinking of projects like the Southern California Edison project mentioned earlier today where it was discovered that an incremental addition should actually go through the CAISO TPP and we thought that any process we developed here should leave the opportunity for processes to be moved into the CAISO TPP if it was deemed appropriate, but we wouldn't see that as the ordinary course of business.

MS. TEETER: This is Valerie Teeter with FERC staff. Just another follow-up question -- so I understand I think what you're trying to get out with this idea of a unified planning assumptions document but I guess I also understand kind of the different purposes of the planning versus the more maintenance type activities and I can see how the full list of things that are in the unified planning assumptions that CAISO puts together, you may not need the same utility level data for the type of document that

you're thinking of here and how certain other things that may not be in CAISO's unified planning assumptions may be key to having at the utility level in the type of documentation that you're looking for.

If you thought through this, if you've got any additional detail you could share about what exactly you would like to see in this kind of base document to kick off the asset management process, kind of planning process, what type of information would you like to see in that besides I think you've mentioned the criteria in determining whether a replacement is needed and understanding how scheduled replacements are prioritized.

MS. MAPES: Let me pull out a document, we have a list actually. So what we had been envisioning as being included in this draft unified planning assumptions document is the -- and I think you mentioned this, the identification and explanation PTO criteria and operating standards, ranking mechanisms for prioritizing projects, descriptions of how criteria and standards are applied to that ranking process.

And then there's a study component -- we'd like to know the list of technical studies and the purpose for which they are being conducted and we'd like identification and explanation of the computer software, methodology and other criteria. And that is our preliminary list.

I think there might be additional information as we think more deeply about this but those were the types of information we were contemplating as an initial matter.

MS. TEETER: Thank you, that's helpful.

MS. AMES: One other question, this is Angela. Would that be on a project by project basis or collectively?

MS. MAPES: I think what would make sense yes, I think yes is the answer to that. For larger projects we'd want a project by project basis but we understand there are certain kinds of projects that would be aggregated so a certain type of pole replacement project we wouldn't ask for each pole to be listed necessarily but we're replacing these types of poles with these types of poles would be the kind of thing we'd expect to see as we go through this process.

MS. AMES: And then it's also to follow-up on that based on the project rather than the dollar?

MS. MAPES: That's a good question and we had thrown around thresholds for dollar amounts. I think that's something we'd be open to discussing. Sometimes it might make sense to apply a dollar threshold and say we only need to talk about individual projects that are over a certain dollar threshold and sometimes it might make sense to say well these are the types of projects that can be aggregated on a year to year basis without us losing any information and that might be the kind of thing we would find as we go

through this process and start to learn what's important.

MS. AMES: Okay, that's helpful and this will all be included in your comments?

MS. MAPES: Yes, we will, did you have a comment Bryan?

MR. GRIESS: Yes, Bryan Griess with TANK. I was just going to -- and a lot of this has already been said but in my mind it's kind of easy to look at it at a very high level. What we're asking for is just some uniformity as to how we can have dialogue to a dialogue and transparency on items like the need to replace items.

I think in most cases what we've learned from what we've seen in analysis, we're probably not going to question the need to replace an item, but where other questions come up is eventually how am I going to replace it?

I am going to replace it in kind? Am I going to replace it with new technology? Am I going to replace it with something that adds capacity? And then when we replace it -- there's going to be some discretion as to when you replace it and how do we prioritize that with other needs of the system?

That's what we'd like to have that to a dialogue.

MS. SWITZER: Okay, PTOs if you have any thoughts or concerns.

MR. NELSON: Well I start with asking the question what problem are we trying to solve -- and I think there's agreement that we don't have a discriminatory access to the grid issue that's really in play here. That's not what the concerns are.

And I think we have consensus when it comes to expanding the ISO's grid and the ISO's transmission planning process it's very robust. I'm not hearing anyone concerned that something's deficient in the ISO's transmission planning process.

What I'm hearing the problem is -- is when we move beyond the transmission planning process to the asset management process that there's not enough transparency. There's not enough dialogue on what's happening.

Now my opinion that this is outside of the scope of 890 -- that we're now talking about maintenance compliance activities, not the transmission planning. With that said, we agree, we think that more transparency in the asset management is healthy.

We think a two-way dialogue is healthy. We think that there is a good reason to be providing more information -- these things are going into rate, people should understand what's going into their rates.

I don't think it's possible to have a unified, unified sort of approach. Utilities are too different, the

asset base are too different, the challenges geographic in the case are just too different.

But nevertheless, our proposal -- our TMCR approved process is not only going to give a five year look ahead but it's going to tell people why we're doing these things, not just the what but the why we're doing it and we plan on putting our criteria or at least the approaches we were using into that into the document that we generate.

We put it out there, we let people see it, we let people digest it then we get together and talk about it. We have the dialogue. We hear what concerns are. We hear what they are saying then we allow for written comments to come in for us to really see it -- maybe the stuff got cleared up, maybe people thought we were doing it this way but we're not and we hear what people are saying.

Now I do have a little bit of concern on going into sort of the micro-managing or mandate of sequencing of event and swatting things in for a lot of the reasons we've discussed. Sometimes things just make more sense to bundle together -- you've got your work crews together, there needs to be some flexibility in how to do things smart that go within the general criteria but certainly can't be memorialized in a checklist of sequence and order that you will follow.

We can't introduce a level of bureaucracy that's

going to interfere with the utilities and I need to emphasize this -- the utility's obligation to maintain a safe and reliable system. We respect the intervenors, we understand that they have to pay for this, but we are responsible.

We are the ones held accountable to make sure that we keep that system to those standards. We have to be able to insure that we can be able to do that. We have to, it's our business. So any process we're talking about that's non-negotiable.

We have to make sure we can maintain a safe system. So we have feedback in ours, we have a lot of final comments, we want to hear alternatives, we see with a five year window, there are times for off-ramps for people to say, look I don't think you should be doing that. We think change the topology is the answer.

Let them get into the ISO's TPP and suggest that to the ISO -- change the topology, and we think there's enough window here that it would work within a process. We've released the final report, we've posted comments -- again we're not trying to keep things secret here.

We have public meetings. We get comments that come in, we then post all the comments for everyone to see, so in case you didn't think of something, it is all out there publicly. We ultimately put out the final report and

in the middle here if there is some flavor of dispute we have an escalation process to get seniors together -- not seniors, management teams together to see if there's some resolution and then we have even a mediation process if the parties agree that mediation might be the right path forward -- I'm checking with my counsel on that.

We release a final report. Some people are going to love it, some people are not going to get what they wanted. Some people are going to say you didn't hear me, why didn't you do this? We then offer another round of before you start this process next time you really need to do, X, Y and Z.

So we can take that into consideration before we start the process next time. So if something came up late or we just didn't think of it there's a change to get it on our radar screen before we start.

So we have a whole feedback process and we feel this transparency is helpful as a two-way dialogue. We want to know if people have issues with things we're doing and if they do we need to really scrutinize that if we think that this is yes, despite people's concerns, this is either a must do or it is the right thing to do.

Now we talked about what happens if push ultimately comes to shove, but providing years in advance warning typically of things that are coming or heads up and

information, they're ultimately going to get into our rate case.

We have another round of data requests, once things get in the rate case. If we know people are not happy about that they're not going to be hidden, they're going to know it's in there, it's worked its way in and then ultimately, ultimately throughout all that process there's still some concerns that was imprudent, that was unreasonable, unallowable activity -- ultimately that gets litigation through the rate case for people to make their case, the Commission that sort of last judgment if whether it was proper spend.

So we are concerned about impeding necessary work with too much process. We think there's a balance, we think we found a pretty good balance, we're open to suggestions but we think we found the right spot. We have 890 well covered in the ISO's processes, there's a legitimate concern about our asset management practices and we're trying to provide more transparency on what we're doing, why we're doing and the decision-making process.

So we have it, we have it. So we think we've reached the right balance with TMCR.

MR. JACKSON: Franklin Jackson, FERC staff. So I'm just wondering in the event that someone does -- someone comes in and says that this project should go through the

transmission planning process, what happens to the project that you've already been planning under the TMCR process?

MR. NELSON: Okay, so I guess there's a level of technical argument here. They may be right. You may see, you're right this has got additional changing the topology or expanding the grid, you're right.

And what we've done in the past is we take that incremental sort of out of our asset management plan and put that into the ISO's TPP, so we would pass this on. Now if there was a disagreement on whether it was or not, at least the stakeholders know it's there, they know what our concern is and if we say we don't think it should -- they have a venue to go to the ISO directly and say hey, do you know that Edison is planning on doing this don't you think they should be in the TPP and then there will be some more conversation.

We may get a call from the owner, why didn't you guys tell me? We did tell you, oh okay. So there's another chance for them to at least know it and have a shot of talking to someone besides us.

MR. SPEER: Will Speer, SDG&E, we're obviously not quite as far along as Edison on that process, we didn't come up with a plan yet to do it. At this point I can't really commit to anything doing that we're not at that place.

But what has been proposed you know, seems reasonable, it does seem to address some of the needs. I do struggle with you know, what's the end game, what's the value. If we're going to add a lot of administrative costs to this are we really going to get value for our customers, I'm really struggling with that personally but obviously we're here having the discussion because there's interest.

So at least from as far as SDG&E what we said we're going down the path with everyone else. I don't know if we have an opinion that this is the right thing to do, but like I said we're behind, we didn't file anything yet.

I think PG&E already has too we haven't done that yet so.

MR. GABBARD: Just to clarify we have not filed anything yet. No I think we generally align in our thinking the challenges are real, we do have to maintain safety and reliability of the grid first and foremost.

The reservations around the inefficiencies to an overly burdensome process, both in -- just in the cost of managing and then the potential implications to that safe reliable operation of the grid are of concern for us, so that's where our reservations are anchored and we want to lead with that that any modifications to the way that we plan investments in the State of California should be only embarked on if we can insure that we are not jeopardizing

those, you know, key pillars in the way that we manage our transmission system.

That said PG&E is supportive of greater levels of transparency. If we try to do what we can to educate and bring visibility to our strategies and our processes and even our project level justifications for the work in our rate filing, we hope that can help move the conversation along.

The concern that I have is that the end game has continued to -- it's not clear but from other parties have continued to signal that the interest is to have a prudency review and a micro-managing process. And now I'm speculating that -- that has not been stated but that's my reservation.

So if we can get to greater levels of transparency without overburdening the process or taking the place of an actual rate filing, I think we might be able to get to the finish line.

MS. BONE: So I have a couple of questions for each of you again. You're investing in transmission infrastructure, three year asset management practices so, you know, we're seeing billions of dollars in the case of PG&E, hundreds of millions, with respect data in the STG&E.

So the question is when does your asset management become transmission planning?

MR. NELSON: I think we've answered the transmission planning is what it is and clearly defined the asset management is not.

MS. BONE: So then what do you see as the difference between what you're referring to as asset management and the PGM PTO supplemental projects?

MS. SWITZER: We don't want to --

MS. BONE: Oh you can't even talk about that, sorry.

MS. MAPES: So I appreciated hearing each of the PTO's thoughts on process and it sounds like there's some general agreement that a process of some sort might be appropriate. I want to read back the idea that we're looking to in PG&E's words micro-manage. I don't think that's a fair characterization. I think what we're looking for is information exchange on both sides.

And we think we can actually contribute. We have transmission planners and engineers and we have experience serving our own customers around the CPUC's case representing 90% of the customers in California and I think that experience will actually contribute to the asset management of the self-approved project process.

MR. THOMAS: Anything else? Any further questions or so forth as it gets later in the day from the audience if they have nothing further, Gary please?

MR. CHAN: My name is Gary Chan with Southern California. Just on your proposed -- on your proposed solution. Would it include stuff like -- projects?

MR. DOCKHAM: I think the simple answer to the question is yes, but you know there are a set of projects that must be done that aren't going to be able to be argued over. How those are done may come into question and I think this document that we are talking about that describes how you are going to approach these projects will make it very easy to say, okay, the project that is being proposed is consistent with those criteria or not.

MR. CHEN: But you would want those projects to be identified individually as opposed to I can't say these are, you know --

MR. DOCKHAM: Yeah, and let me give you an example. A substation hardening project you know, that could be a chain link fence, it could be a block wall, it could be a marble wall.

Some ability to look at a project that is just outside of any expected norm for expenditure would be ripe for question but on balance we wouldn't expect a whole lot of discussion or argument over those NERC reliability XO projects.

MS. LOOKER: To add my two cents to that, this is Geneva. I think with those kind of things where you want to

keep locations and other things quiet or confidential, if we don't do an NDA process or something it might be sufficient, you know, to have a list of okay, we have X number of substations that we need to do some work on and we anticipate each of them to cost X, Y and Z and the reason they're going to cost X, Y, and Z is because we plan to do boom, boom, boom, boom, boom.

That then allows us to have an idea of the magnitude of the costs, whether we think what you're planning to do is reasonable or not. You know, so I think that those are things that we can, especially in that first phase where we're looking at the assumptions and criteria we can sort of talk it over and decide what is going to be necessary.

Because eventually I think, you know, some of these things will pass. You'll have them all done and granted new ones might come in. But there can be some give and take on that.

MR. NELSON: So what we proposed in our TMCR was to aggregate and give collective spend so it's federal criteria that we're following, aggregating, letting people know how much we're planning on spending because of these concerns.

They have real concerns about dividing too much information.

MS. BONE: And, I realize that as we end up closing here as a representative of the utility's regulatory there have been a number of questions that have come up about, you know, is this going to end up being a type of prudency review?

And my position -- I can't speak entirely for the CPUC, but my position is that we are doing this process and we are seeking the information now to avoid having to get to the point of doing prudency reviews in the rate cases.

We want to be talking about these projects now, understanding that they're needed and that they're appropriate now and then there's no need for prudency review because we're all on the same page.

So it's about getting involved earlier in the process rather than doing after the fact challenges to projects where money has already been spent, projects are nearly built and it's really too late.

So I hope that answers your question on that point.

MR. THOMAS: Yeah, that was very helpful. And as we're ending I think that a lot of the discussion and the Q and A was very helpful today to understand what goes on. So hopefully we can take this back to the Commission, the record will speak for itself as you see on the notices you'll get to provide brief comments thereafter.

MS. SWITZER: Yeah, I would just say that this is all in the notice but initial comments are due on or before May 31st and reply comments are June 15th.

MS. BONE: And I take it that if we have a tariff line probably to make that would be an attachment and would not count against our 15 page limit.

MR. THOMAS: Technicality, I'm not going to lie, I would prefer it not to but there may be further supplemental notice out to you to provide greater guidance so let's see what happens.

MS. BONE: Okay.

MR. PATRIZIO: Very technical questions -- how do we go about getting a copy of the transcript of today's comments and do we have to sign-up for that or will it be emailed to the participants? How does that work?

MS. SWITZER: So the transcript's available almost immediately from FERC via Ace Reporting Company and their information is in the supplemental notice from April.

MR. PATRIZIO: Thank you.

MS. SWITZER: We're letting you out a whole hour early, wow. Thank you so much, it was a very helpful, thank you.

(Whereupon at 2:56 p.m., the conference was adjourned.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding:

Tansmission Planning Within The California Independent System Operator Corporation

Docket Nos.: AD18-12-000; EL17-45-000;
ER18-370-000

Place: Washington, D.C.

Date: Larry Flowers

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

Larry Flowers

Official Reporter