BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the matter of,) Docket No.11-IEP-1E,11-IEP-1G

IEPR Committee Workshop on Transmission Needed to Meet State Renewable Policy Mandates and Goals

IEPR Committee Workshop

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

TUESDAY, MAY 17, 2011
9:00 A.M.

Reported by:
Kent Odell

COMMISSIONERS

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Carla Peterman, Associate Member

STAFF
Grace Anderson
Judy Grau
Suzanne Korosec
Paul Feist

PRESENTERS (*Via WebEx)

Grace Anderson, CEC
Mohammed Beshir, California Transmission Planning Group
Judy Grau, CEC
Neil Millar, California Independent System Operator

PUBLIC

Rich Lauckhart, Black and Veatch
Steven Kelly, Independent Energy Producers Association
Eugene Wilson, Sierra Club, CA Energy and Climate Committee
Carl Zichella, NRDC
Daniel Hodges-Copple, Clean Line Energy Partners
Ron Dickerson, Save the Foothills Coalition
Jim Stewart, Sierra Club, California

Panel Discussion #1

Jon Eric Thalman, Pacific Gas & Electric
Robert Woods, Southern California Edison
Will Peer, San Diego Gas & Electric
Stephen Keene, Imperial Irrigation District
Mohammed Beshir, Los Angeles Department of Water & Power
Lorenzo Kristov, California Independent System Operator
Anne Mills, California Public Utilities Commission

Panel Discussion #2

Carl Zichella, Natural Resources Defense Council
Tony Braun, Counsel to CA Municipal Utilities Assn.
Neil Millar, California Independent System Operator
Mohammed Beshir, Los Angeles Department of Water & Power
Anne Mills, California Public Utilities Commission
Ziad Alaywan, Z Global
V. John White, CEERT
Darlush Shirmohammadi, California Wind Energy Assn.
Robert Jenkins, First Solar, Inc.

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P R O C E E D I N G S

MAY 17, 2011 9:05 A.M.

MS. KOROSEC: Good morning, everyone, we're going to go ahead and get started. I am Suzanne Korosec and I manage the Energy Commission's Integrated Energy Policy Report Unit.

Welcome to today's Workshop on Transmission Needed to Meet State Renewable Policy Mandates. This workshop is being conducted by the Energy Commission's Integrated Energy Policy Report Committee and we're joined today by Commissioner Peterman, who heads the Renewables Committee at the Energy Commission.

Today's workshop will contribute to the development of the strategic plan for increasing renewable generation and transmission infrastructure in California, which is part of the 2011 IEPR. Public Resources Code requires the Energy Commission to adopt a strategic plan for the State's electric transmission grid as part of the IEPR and, in past years, that strategic plan has been a standalone document; however, with this IEPR's focus on identifying the most effective ways to facilitate meeting California's 33 percent renewable portfolio standard and integrating 8,000 megawatts of utility scale renewables as called for in

Governor Brown's Clean Energy Jobs Plan, the requirement for a transmission strategic plan will be met by the Transmission Section of the Renewables Strategic Plan.

Just a couple of housekeeping items. Restrooms are in the atrium, out the double doors and to your left. We have a snack room on the second floor at the top of the stairs, under the white awning. And if there is an emergency and we need to evacuate the building, please follow staff to the park that's kitty corner to the building and wait for the all clear signal.

Today's workshop is being broadcast through our WebEx Conferencing system and parties should be aware that you are being recorded. We will make the recording available on our website within a couple of days of the workshop, and we'll also have a written transcript available within about two weeks.

Our Agenda today begins with an overview of the workshop goals and next steps, followed by presentations on transmission plans for interconnecting large-scale renewables. We will then move on to our first panel, which will discuss challenges to interconnecting renewables to the transmission system and recommended actions to address those challenges.

We will then have a presentation on Western interconnection regional planning as it relates to renewables, followed by an opportunity for public comments for those who may have a time constraints and aren't able to stay until the end of the day. We hope to break for lunch around 11:45, depending on how the morning's discussions go.

We'll reconvene after lunch at around 12:45 with our second panel on recommended actions to ensure timely transmission system upgrades for renewable generation. After the panel, we'll have a second opportunity for public comments.

During both of the public comment periods, we'll take comments first from those of you who are here in the room, followed by comments from those participating via WebEx. For those of you in the room who wish to make comments, we ask that you fill out a blue card, these are available on the table out in the foyer, and you can give those to me at any time during the day. And also, please indicate if you have a time constraint and need to speak in the morning, rather than being able to wait until the afternoon.

When we call on you to speak, please come up to the center podium and use the mic so that we make sure we capture your questions and comments on the record, and it is also helpful if you can give our Court Reporter business cards so we make sure your name and affiliation are reflected correctly in the transcript.

For WebEx participants, you can use either the chat or raised hand functions to let us know that you have a question or comment, also whether you have a time constraint, and we'll either relay your question or open your line at the appropriate time. For those participating only by phone and not through the WebEx system, we'll open those lines at the very end of the day at the public comment period.

We're accepting written comments on today's topics until close of business May 24th, and the notice for today's workshop, which is available on the table in the lobby and also on our website describes the process for submitting comments to the IEPR docket. And with that, I'll turn it over to the dais for opening remarks.

CHAIRMAN WEISENMILLER: Thanks, Suzanne. I'd like to thank everyone for coming today. This is going to be an important workshop. I think all of you know that this IEPR is really going to focus on the strategic plan for renewable generation and transmission. Today we're really going to try to flesh out the transmission part, but at least the transmission part for the large-scale, utility scale renewables.

I would like to thank Commissioner Peterman for sitting in and also would like to introduce Michael

Picker on my left from the Governor's Office, again, emphasizing the importance of this to both the Commission and the Governor's Office. Again, we're trying to cover a lot of groundwork today, so we certainly encourage people to stay on point and we're looking forward to an interesting and stimulating conversation.

COMMISSIONER PETERMAN: Good morning. Once again, glad to have you here with us. Looking forward to your expert input and thoughts on these issues. It is indeed very important for those of us working on renewables and for Chair Weisenmiller and I, who also serve on the Electricity and Natural Gas Committee. And with that, I'll turn it over to the other people on the dais.

MR. PICKER: Thank you. Since I don't have an official role as a Commissioner, I get to speak my mind and I just wanted to make a few comments based on my limited experience in the field of renewables, and I come to this as a newcomer, so some of this may be really obvious to people who have been in the transmission field for a long time, but I think it's useful to have some sense of how other stakeholders who have an interest in the growing renewables portfolio in California, and how this affects our work.

And I would just remind folks that, when I first came here, I was assured that my job was simply to deal with the incredible obstacle of land use in terms of large-scale renewables projects, that transmission was pretty much sorted out by RETI and that there wasn't a whole lot that I would really have to do in this arena. And currently, this is probably at least 50 percent of my portfolio, and unfortunately, none of the people who sold me this bill of goods are still around for me to blame on it.

But, having talked to the wires folks in the last couple days, they assure me that the cost on an annual basis of upgrading our antiquated bulk transmission grid nationally is around $12-15 billion per year. And so, if that was extended to California, we clearly would be spending around $1.6 billion a year, which is a hefty expenditure. However, it doesn't really compare to what we've been spending, both in taxpayer dollars and ratepayer dollars on our Renewable Portfolio Standards, so it's an important piece of the infrastructure that we need to support this rapidly growing area of our electrical grid.

Last year, we tracked around 20 large renewables projects over 200 megawatts and 13 of those projects got permits last year, representing about 5,300 megawatts.

They're all in places where we don't have adequate transmission to move those electrons to consumers. We've already added another 1,200 megawatts this year and we're tracking another 35 projects that represent 7,200 megawatts that expect to get permits and begin construction this year.

So, clearly, this is unprecedented in growth in areas that we don't currently have transmission. It's related to the deadlines that are contained in Federal stimulus dollars, but there's no doubt that the pace at which bulk transmission upgrades are being completed has significant impacts and poses some challenges to the ability of these projects to both interconnect and to finance.

I would just point out that the Energy Commission issued a Land Use Permit for one project last year in less than 11 months, and if it takes a year and a half to two and a half years to go through the CAISO's new Cluster Queue process, there's a lag time already in the system. If we use the approval of those projects in the cluster process as a basis for determining the need for project upgrades or new transmission lines, then you can add more time to that delay, four years. If you figure that the average time to get through the planning and permitting process at the CPUC is another three years, we're at seven years, and if you add construction time at the utility end of three to five years, then we're talking about 12 years. We're permitting projects and they're beginning construction on about a year time schedule, and it can take us as long as 12 years to complete the upgrades -- that's a worst case, but it's a reality.

So there's a mismatch here and we clearly have to figure out ways to plan better, to execute better, to match the timelines at which we're swapping out older carbon fueled electrical projects in our electric grid and replacing them with renewables. Otherwise, it just won't work. So that's one of the significant challenges that we hope to find out solutions for in the discussion today and through the rest of the IEPR.

There are other issues, including what's the nature of the Western Grid, is it going to be a balancing portfolio? Or is it going to be a one-way pipeline to California that looks like radial system from California to remote areas. Will California ever be an Exporter? Can we come up with a way to create a dynamic Western Grid that shares resources? What do we do about the distribution grid where, in some cases, the lines and the transformers can be as old as 80 years and may not well be suited, that we don't have the safety systems and the design that will support 12,000 megawatts of distributed generation within the load center areas? All these issues are pretty important for us to begin to hammer out really quickly and I know that we’ll probably solve them by lunch today, so thank you.

MR. FEIST: Thank you. Commissioner Douglas couldn’t be here today, she’s at the DRCP meeting in Ontario today, and we expect that process will have a bearing on transmission policies as we go forward. But she asked me to thank all the participants and she’ll be reviewing the record carefully. Thanks.

MS. KOROSEC: All right, we’ll start with Judy Grau to give us an overview of the workshop goals.

MS. GRAU: Thank you, Suzanne. Good morning. As Suzanne mentioned, this workshop will contribute to the development of the Energy Commission’s 2011 IEPR and, in particular, this supports the IEPR’s focus on a 33 percent Renewables Portfolio Standard by 2020, and integrating 8,000 megawatts of large-scale renewables as envisioned in Governor Brown’s Clean Energy Jobs Plan.

As we have done in past IEPR cycles, the Commission began the transmission data gathering process by adopting transmission forms and instructions on January 12th of this year, and then we received responses to these data requests from 14 electric utilities, including both investor-owned and publicly-owned utilities.

In March of this year, our IEPR Committee revised its Scoping Order and directed that we produce a subsidiary volume to the IEPR called the Strategic Plan for Increased Renewable Generation and Transmission Infrastructure in California, which we have shortened to the name “Renewable Energy Strategic Plan.” And, as I believe Suzanne also said, this subsidiary volume will meet the requirements of Public Resources Code 25324, which directs the Energy Commission to adopt a Strategic Plan for the State’s transmission grid. And so, therefore, instead of producing a standalone Strategic Transmission Investment Plan, as we have done in 2005, 2007, and 2009, that work will be folded into this Renewable Energy Strategic Plan.

And this is the list of the utilities from whom we receive responses to our data requests, and this map, which you also hopefully picked up a full color copy of, because it’s easier to read, based on the transmission forms and instructions responses we received, we prepared a comprehensive map that shows the major transmission lines to support these renewable energy mandates.

So, the CAISO projects, they are included in the

Draft 2010-2011 Transmission Plan, which we'll be hearing about next from Neil Millar, that draft plan was published on March 24th and it's scheduled for adoption at the CAISO Board of Governor's tomorrow. This draft plan was cited as an information source in the Utilities' responses to our Forms and Instructions. And so, for purposes of this map, we've grouped the projects in the CAISO's Draft Plan as follows: the projects in red, numbered one through four, have been approved by the CAISO and have also received their Certificates of Public Convenience and Necessity from the California Public Utilities Commission. The projects in gold, numbered five through nine, have been approved by the CAISO via the large generator interconnection process, but have not yet filed for their permit at the CPUC. And the one project in purple, number 12, is the one policy driven project identified by the CAISO in its Draft Plan and, again, we will have Neil Millar discussing this plan in more detail.

The Imperial Irrigation District in Los Angeles Department of Water and Power approved projects were cited in their responses to our adopted forms and instructions. The ID projects are shown in blue, while the LADWP projects are shown in green. And as I mentioned, we have representatives from Panel 1 from each of the investor-owned and publicly-owned utilities who can speak to these projects in more detail.

We have four main goals for our workshop, first, to describe the transmission system plans for interconnecting large-scale renewables in California, then discuss the progress made in the development of transmission infrastructure to facilitate renewable generation; we want to address the interaction between California and the rest of the Western interconnection, and recommend actions to ensure timely transmission system upgrades for renewable generation. We have sought to capture panelists who represent a wide range of perspectives, so that we can capture all sides of the complexity of these issues.

This workshop and any follow-up written comments we receive will then be used to create the record for the Transmission portion of our subsidiary volume entitled the Renewable Energy Strategic Plan.

And so, with respect to the first goal, we have two presentations that set the stage for the workshop. These include Neil Millar’s presentation on the CAISO’s Draft 2010-2011 Plan, and also a presentation by Mohammed Beshir on behalf of the California Transmission Planning Group, or CTPG, on their 2010 Statewide Plan. And we will then have the first of the two panel discussions, the first panel will focus on the challenges to and progress made on interconnecting renewables to the Transmission System. We've asked each panelist to take no more than 10 minutes for their opening remarks.

One thing on your slides, we have Robert Woods' title incorrectly listed, his actual title is Director of Electric System Planning for Southern California Edison. And in this panel, Mo Beshir will be representing LADWP, not CTPG, so he will have to change his hat for that.

And then we will have the presentation by Grace Anderson of Energy Commission staff on the Western Interconnection Regional Trends and Initiatives. One note here, there are two public comment periods, one in the morning, and one in the afternoon, however, we ask that you speak in only one of the two comment periods, not both. We would ask that the morning comment period be limited to those folks who have a time constraint and are not able to comment in the afternoon. And, finally, we ask that all public comments be limited to no more than three minutes.

After the lunch break, we'll convene our second panel to address the questions of what changes should be made to the existing transmission planning, permitting, and construction processes to ensure that appropriate and timely upgrades that support renewables are completed, and also what additional changes would enable the planning permit construction cycle to be shortened to ideally no more than three years, without sacrificing the quality of the decisions, and this gets back to the point that Michael Picker made about the disconnect between how long it takes to plan a permit and construct transmission vs. the generation it is seeking to reach.

We've asked each panelist to take no more than five minutes in this panel for their opening remarks. We have, again, Mo Beshir on this panel, now he's back to represent CTPG. We also have Neil Millar on the panel representing the CAISO, and Anne Mills is also doing double-duty on this panel, too.

Then, finally, we will take public comments for those folks who did not get a chance to speak in the morning. And, just briefly, this is the schedule and I believe we will put this up at the end of the day; written comments will be due one week from today, late August is when we will be publishing the draft version of the Renewable Energy Strategic Plan, and we will then have a workshop set for September 14th on that, and then the rest of the IEPR schedule with the Committee Draft IEPR in late September, hearing on October 12th, that's already been set, and then the Business Meeting adoption of the complete IEPR in November.

And so, with that, is Neil Millar available? Okay.

MR. MILLAR: Thank you very much. First, I just want to say thank you for the opportunity to address the panel. And I'll move through a few slide presentations that hopefully will provide some context for the rest of the discussions through the day. There's a fair bit of material, some of which has already been touched on, so I'll move more quickly through that material.

First off, the 2010-2011 ISO Transmission Plan was already referred to, it is going in front of our Board of Governors tomorrow for approval, and this is a fairly exciting time for us because this is the first transmission plan brought forward under our new tariff and under a revised planning process. It does provide a number of key changes in terms of our planning process, first is the additional opportunity for stakeholder involvement through the development of a conceptual statewide plan to ensure better coordination with other control areas inside the state, as well as outside. It does provide for policy driven transmission, which is a major change for us. It also creates more opportunity for independent transmission developers to compete on particular solutions, for particular policy driven and economically driven transmission elements, and more opportunities throughout the process for stakeholder participation and input.

The process itself is a three-stage process with opportunities for input through the development of an actual study plan and input assumptions; phase 2 is the detailed analysis, landing on recommendations that ultimately reach our Board of Governors for approval; and the third stage, if there are projects that fit into those categories, that is for the competition between independent transmission companies and the investor-owned utilities for the actual development of those projects.

We refer to the Transmission Plan as a “Comprehensive Transmission Plan” primarily because it’s coordinated with other control areas inside and outside the state, as well as looking at all aspects of transmission need inside our control area. That includes reliability needs, the basic requirements to keep the lights on. Next, we layer on the requirements to meet policy objectives and, in this case, the primary driver is the 33 percent RPS goals. And then, lastly, we review the plans developed to that point to see if there is congestion on the system, primarily affecting thermal generation that would warrant additional transmission upgrades. I do want to emphasize that economics are considered in developing the least cost solutions at each of the earlier two stages. The third stage is focusing on generation congestion.

Before I touch on the policy driven projects, the plan has also identified this year 32 reliability projects totaling $1.2 billion; most of those projects are below $50 million, but I've also identified on this slide four larger projects that are also being brought forward for approval.

When we look at the policy driven requirements, the planning is focused primarily, first, under renewable energy zones -- where are the resources that we're trying to access, focusing on solar, wind resources, and geothermal. And this slide simply highlights where some of those resources are located across the state. We then develop a portfolio approach, looking at different ranges or ways in which the State could meet the 33 percent RPS. Each of these is focusing on slightly different conditions. I know there is a lot of material on this slide, but hopefully this will also provide a record of the information.

Last year, the ISO focused on four scenarios, picking the middle of the road case, the hybrid case is our base case for planning purposes, but also testing what would be required under different scenarios looking at higher in-state utilization, higher out-of-state important, and also higher amounts of distributed generation, how that would affect the planning. And then the goal is to move forward with those projects that most comfortably meet the needs of a number of those scenarios as a way to handle the uncertainty about how the State will actually meet the 33 percent RPS goal.

This is the same information provided graphically, so I won’t spend much time on it. In terms of meeting the 33 percent RPS standard, the ISO has also considered in its planning process the projects that are already moving forward, that have either been approved through prior processes, or that are advancing through the large generator interconnection process, as that parallel process also identifies network upgrades. And we assumed that those projects are moving forward until there’s a reason to doubt that, we factored that into the planning, and then look at the additional requirements. As was already mentioned, in this year’s plan, we have identified one upgrade project to transmission relating to Path 42, a reconductoring project that Southern California Edison would be taking on, and while this is a policy driven project, this one is not eligible for competition strictly because it is an upgrade to existing Southern Cal Edison facilities, given that it's modifying facilities they already own and operate, it's not appropriate to put that out for competition. The total project bill there adds up to $7.2 billion, but the new project being identified in this plan is $40 million.

I've also added this slide just to highlight the degree of uncertainty that exists in how the State will meet the 33 percent RPS goals. With the addition of the generation projects that applied for interconnection through the ISO's most recent Cluster 4 application process, which were an additional 193 generation projects that brought the total renewable generation in the ISO's interconnection queue up to just below 70,000 megawatts. Now, recognizing that to reach the 33 percent RPS goal requires something under 20,000 megawatts, that just highlights the amount of uncertainty that exists as to which particular projects will be moving forward.

So, in conclusion, I just want to touch on a few points, first, is that the transmission that is approved to date and moving forward through the processes does in the ISO's view provide a way to meet the 33 percent RPS goals, it provides some cushion, as well, for some uncertainty, and we don’t believe it is appropriate to move forward on approving additional new major projects at this time. I have to qualify that, that this is based on a particular set of assumptions, and as those assumptions change, are updated as we move forward, the ISO does intend to reassess its transmission needs as we move through our next annual planning process, which has already been initiated. We will be able to rely in the next cycle on the CPUC portfolios that were developed and finalized towards the end of last year, those will be the portfolio cases that will be taken forward in the 2011-2012 planning cycle. And in the mean time, we do believe that the focus within the State does need to be on finalizing the permitting and moving forward with the transmission that has been identified to date, also as a way to address the uncertainty that exists in the wide range of potential that exists for meeting the 33 percent RPS goals.

Those are my introductory comments for now. I believe we’ll be taking questions later through the panel, but if there is anything else –

CHAIRMAN WEISENMILLER: A couple right now.

MR. MILLAR: Sure.

CHAIRMAN WEISENMILLER: The first one is, what were the surprises that came out in this planning process?

MR. MILLAR: I'm sorry?

CHAIRMAN WEISENMILLER: What were the surprises or unanticipated results in this planning process?

MR. MILLAR: Well, I do believe for many of our stakeholders, they were surprised that the projects already underway were capable of delivering the amount of renewable resources to the Grid that the plan can accommodate. I think that was probably, for industry, one of the fairly significant surprises.

CHAIRMAN WEISENMILLER: Great. And on your slide that talked about the – when you talked about the interconnection queue, could you provide us later a breakout of where the projects are in the queue in terms of the transmission locations?

MR. MILLAR: Yes, we can provide that.

CHAIRMAN WEISENMILLER: And you heard Picker's earlier conversation about how we're trying to basically accelerate the transmission process, do you have any suggestions on how the ISO can do things quicker?

MR. MILLAR: The single biggest impediment in us moving more quickly is the uncertainty around the range of potentials. So, certainly, what helps us move forward more quickly on approving generation -- or approving transmission to accommodate the generation is, as the load serving entities move forward with contracting for resources, and those contracts are approved, that takes additional uncertainty out of the mix and allows us to move forward more quickly. In terms of the timeline of the process we have, most of that right now is driven by the opportunities for stakeholder consultation, so tightening those timelines and reducing opportunities for stakeholder consultation carries a risk with it. There is that tension between how quickly can we move and how quickly can we keep stakeholders informed and giving them opportunities to participate. That's something we're obviously more than open to revisiting, but that's probably the most significant timeline impact right now.

CHAIRMAN WEISENMILLER: Okay, and would you talk a little bit more about the role of the LGIAs for the ARRA projects in this Transmission Plan? How did that drive the results?

MR. MILLAR: There were several changes here. In our annual planning process last year, timelines were shortened largely courtesy of a fair bit of overtime by some of the ISO staff to produce quicker results, to allow a number of the ARRA projects to move forward, and meet their timelines. Now that those timelines have been compressed, that's become part of the going forward process, so that tightening of the process itself is now part of the new process. The other changes that we made were, going forward, there's an expectation or a requirement that, in our annual planning process, we will review the network upgrades, certain large network upgrades that have been identified in the generator interconnection process, and review those for further opportunities to enhance those projects, or to merge them with other projects, and we did seek a relief this year from – a one-time relief – from FERC for that process because that created an additional timeline challenge and additional uncertainty for the ARRA projects. So, in this cycle, we took the network projects that were identified through the previous generator interconnection process, assumed that those will continue to move forward, and then did the rest of the planning around those projects, as opposed to going back and revisiting the need for those projects, themselves, or if there were different ways to enhance them. So, we did make those changes specifically this year to accommodate the ARRA projects and to make sure that that wasn't the reason that those were held up.

CHAIRMAN WEISENMILLER: Okay, and last question was just in terms of, what were the results for the independents in this process?

MR. MILLAR: Well, in this cycle, there are no projects that are moving forward that would be eligible for competition. The only policy driven project in addition to the LGIA driven projects was the reconductoring project for the Mirage-Devers circuits, which are owned by Southern California Edison. So, in this cycle, we haven’t identified any additional policy projects that would be eligible for competition.

CHAIRMAN WEISENMILLER: Okay, thank you. Michael.

MR. PICKER: First, let me thank ISO for its good work in developing new systems for considering the interconnection request, the Cluster process is a useful innovation and it takes us part of the way to where we need to go. So I wanted to follow-up a little bit on Commissioner Weisenmiller’s question about getting the locations of the new projects in the interconnection queue. This is something that I think we all need to think about. The assumption has been, in part, that as the Federal Stimulus Program started to go away and these projects began to look at a development horizon that was driven by the PTC, rather than the cash grant in lieu of tax credits, that things might slow down. The amount of interconnection requests you received at the end of March kind of argues that there is still a huge interest in developing generation to serve California's load needs under the RPS standards. And so some of this is likely to follow the RETI work, which many developers continue to believe was instruction from State Government, State agencies, as to where they should locate. And so those clusters, then, help us to define where we're likely to see large groups of generators located. So, having that gives us at least a land use perspective. And I guess my question is, is it possible for CAISO, because you're the only people who have real information about these internet connection requests, to begin to do some long range perspective planning that gives us tools to really evaluate and to debate whether there are areas that we should encourage first, and areas later, so that we can pace the growth of transmission? I'm searching for a way that we can get out of the box that we're in of land use coming in advance of interconnection requests, and coming in advance of upgrade and new transmission approval. What are the tools that you can take from these early things, these early connection requests, to begin to give us some picture of what's coming at us over the horizon? Do you have thoughts about that? Have you ever had discussions about that?

MR. MILLAR: The issue of how to handle and manage this level of uncertainty and marry that with the rest of the information we have about generation development is getting a lot of discussion because – I was told we should never generalize when itself is a generalization, but, in general, most of this additional generation is already located in areas where we are already moving forward with transmission, they're simply much much more of it in each of those areas. So, that indicates that there's fierce competition between different renewable energy zones, as well as within each of the renewable energy zones. So, I haven't seen anything yet through the interconnection requests, the additional interconnection requests, that would suggest to us that the work done to date to both the renewable energy zones is flawed. Now it's more of a question of which projects will be moving forward, and will the competition itself with load serving entities result in one area being favored more strongly than others. I think the tool there -- and I think I'm going to get eventually to the answers, sorry –- I think the process that we're actually working on is on the right track, relying on a portfolio approach that helps us bound what is a reasonable expectation for the State to want to rely on these different zones, and then plan the transmission accordingly. The risk in that process is that, with that information, if the generation isn't firmed up, it just extends and continues the uncertainty into the next cycle and the next cycle. So what we really need, I believe, to provide that clarity is some focus on the areas that transmission is underway on, and then factor in any new intelligence that is learned into the next cycles.

MR. PICKER: Okay, but even your observation that many of these projects are clustered in areas where there are already projects is useful policy information if we can qualify it in ways that allow is to say that it may be that we should expand existing corridors for transmission, and we should start that now, and that either the existing utilities or other transmission providers should start looking for those opportunities in the out years because I'm not sure that we have that process underway.

MR. MILLAR: I don't believe we have yet. I do have to point out that, with 70,000 megawatts in the queue, and a peak load of about 50,000, starting a transmission planning process that could accommodate the maximum in each area, I don't believe, would be –- well, for one thing, it wouldn't be financially prudent and, for another, it would create huge stakeholder backlash in each of those areas because the transmission facilities required to take each area to its individual maximum are far beyond the facilities that we already have moving forward. And, practically, we don't expect any one renewable energy zone to reach its maximum at the expense of every other zone inside the state. So, finding that balance, I think, needs to be done in a pragmatic fashion.

MR. PICKER: I think that there is a challenge of finding the right balance here, I'm not sure what it is, but I know that we're too far one side right now.

MR. MILLAR: But planning for all of it would take it to the other extreme.

MR. PICKER: That's correct. So, how do you handicap it? What are the viability screens? And how can you do that far enough in advance that it's useful information?

MR. MILLAR: Agreed.

CHAIRMAN WEISENMILLER: Thanks.

MR. MILLAR: Thank you very much.

MR. BESHIR: Good morning. Thank you for the opportunity to comment and discuss the CTPG work, specifically the 2010 statewide transmission planning activities. As you may know, the CTPG is a brand new organization which was, for the most part, a good portion of that work was done in 2010, and as you can see, some of the logos there, and these are the companies and entities that are present to the CTPG.

So just to summarize the introduction, the CTPG is a coalition comprising all entities within California which are responsible for transmission planning for the Interstate and Intrastate Grid. We have publicly-owned utilities, IID, TID, SMUD, and LADWP, as well as California ISO, and investor only utilities, PG&E, SCE, and San Diego Gas & Electric, as members or participants in that organization. For the most part, the work we've been doing really is transmission planning studies, so we are not really involved in major economic analysis or really trying to work out any major decision as far as approval or authority or development of any specific transmission projects. Essentially, we're really looking from a need point of view to try to understand what the need of the state is to meet certain policy goals.

So one of the key activities for us, of course, being the open or transparency process, so we have engaged pretty large activities related to the public with stakeholder meetings and, also, we do provide pretty good service in providing and posing our comments and answering questions to participants in most of our activities, and we also have either WebEx, as well as face-to-face stakeholder meetings on an ongoing basis. So those are really the key things we've been working on.

So, the key for us to identify transmission additions for 2010 was to look at the 33 percent and meet the State goal by 2020, and that was the main focus of the work which CTPG did in 2010. And part of the activities was to integrate the delivery of renewable energy to load centers with reliability, as well as operation needs of the Grid. We do understand, of course, the benefit of a collaborative planning approach, and we do believe that it significantly reduces the economics and the environmental cost of achieving the 33 percent, and that being really the key focus of the activities before us.

So, for 2010, early on, we did set up what the objectives for the studies were for 2010, and the objective was to complete a statewide conceptual transmission plan by the end of the year, and also work with the stakeholders in developing that plan. We have originally had different views and different ways we have tried to figure out what needs to be done, there was a lot of learning in the process, being the new organization, but essentially it was developing multiple scenarios and to try to find out what the likelihood of the scenarios would meet the need for the 33 percent. At the end, the idea was to really come up with different ways of looking at it and identify what we consider, given the probability of things and the centers we have analyzed, to come up with what we call “high potential transmission needs” and looking also at the state balancing authority areas for development by 2011. So, that was really the key goal for us, so that was done in 2010. The process, as I said, there was a lot of learning going forward, so we started with different phases, in fact, when we did get to this, we didn’t know we would have four phases, but of the four phases I have shown here, show different things and different activities we’ve done. In the early stage, of course, in Phase 1, there was a lot of development activities on the membership and organizational issues associated with CTPG, and also work-out of the stakeholder process, and luckily the stakeholder process, we depended and used tremendously to our advantage was a RETI process, and we used RETI a great deal as far as from our stakeholder process is concerned.

And originally, in Phase 1, the focus was looking at the balancing authorities and looking at their planning, and looking at the 33 percent from their perspective and working out the plan from the balancing authority point of view. In Phase 2, we did involve a great deal of the stakeholder process, we did use RETI, as I said, specifically in setting up the Net Short, what the Net Short is going to be, and at that point we defined the overall Net Short that we were going to target was about 52 or 53 terawatts as a goal for us to meet the Statewide 33 percent RPS by 2020. We moved, as time goes to Phase 3, the key activity in Phase 3 was we involved other entities outside the balancing authorities, or the transmission providers, and independent transmission providers to provide as a mitigation, as transmission options, or concepts, they may have tried to see if they can see, from the work we have done, meets some of the needs of the transmission for California. So we did go through that analysis in Phase 3.

In Phase 4, it was working on looking at all the phases we have done, tried to figure out what the high potential transmission projects would be, and that led to developing the statewide plan by the end of the year in 2010. So, we just wanted to give you an understanding of the kind of effort and work went through that, and this is kind of the timeline. As you can see, we did go through the whole year, going through the different activities, and there were overlaps between one phase to another phase as we find out that we need to go to a second phase and address different issues. We started that process, the stakeholder process, developing the study plan, and working out the activities and developing the scenarios that took many months and leading to the Statewide Plan issued in January 2011.

So, based on the work we've done, we came up with a set of transmission projects we thought are really essential to meeting the 33 percent by 2020. As I will tell you shortly, this we didn't think was really the full picture, per se, because the scenarios and the way we have done the work really identified a set of transmission which we thought were high potential, would be the basic needs to meet the 33 percent, but there was also recognition this has to be further refined, and also be further looked at in 2011 and beyond.

The key transmission – in fact, I just anticipate some of the questions – there was no really major surprises, per se. A good portion of some of the transmission lines were already being considered, or looked at, or been in some way or another in some processes from a development perspective. You may see some transmission here which obviously are moving, but they were in the base case, which are in the base assumption, so they would show as a given transmission, so you would not see, like for instance, the Sunrise Transmission Project would not show up because it was already in the base case assumed because it has gone through a set of environmental approvals, so a good portion of what was through in the environmental approval, going through some balancing authority approvals, would not show here because they would be already in the baseline assumptions. So a good portion of the transmission, as you can see, probably was in the southern portion of the state, and based on the scenarios we have done, this one we have looked at different activities, but for the most part, we have tried to maximize the in-state resources to meet the 33 percent. Furthermore, we did identify corridors, we have done scenarios where we did see high potential corridors which in future analysis we need to expand and see the need of expanding those corridors. So we did identify three major corridors which would meet, depending on the safe policy, and how the renewables would be coming to meet the 33 percent in the future, as far as discussion and further analysis.

So, overall, even though the transmission segments may be small, but we have identified up to 26 transmission items which could be reconductoring, transformer connections, and what have you, in the 2010 Statewide Plan. And a good portion of this was really to come up with what we think would be high, the needed, and we would need to move forward to the next steps with the balancing authorities, whoever needs to take that information, which we made available, whoever needs to move it forward, we thought that was parties that need for this high potential transmission.

In addition to the high potential transmission, we also identified what we would call medium potential transmission. They didn’t really meet the guideline or the level we thought they may require for the high potential, but they are also needed and, given a certain set of assumptions, or scenarios, they could also be high potential. And though we have identified 34 transmission items, also, which really meet what we call the medium potential activities and, as I also said, there were three transmission corridors which identified, depending on out-of-state scenarios which could meet – were maybe required for the 33 percent.

In the 2010 Statewide Plan, we identified not only the transmission, but also looked at some of the shortcomings of the way we have done the work, so one of the things we tried to do was really correct some of the errors, or correct some of the things we have done, so that we could improve our process. There were a lot of lessons learned. So what we've done is to, for 2011, we did a pretty large planning process, so that we do really go through this multi-phase approach, we do involve the stakeholders early on, get all the input, and in the development of the different activities. So in the Phase 1, as you can see, we had identified major items which we really need to work out and develop consensus and understanding how we're going to really approach the 2011 studies. So, the key approach was what kind of base case we're going to work out, the existing renewables we have in 2010 base cases, and studies we have whether the renewables out there, are they still staying, whether they are still continuing in the process. So we need to re-tune and figure out those issues.

A big component of the way we do studies is really the OTC plans because of the ongoing activities on the OTC, we want to figure out exactly if we can the configuration and the level of the ocean-cooled generation plans we have in the state, and how they're going to be appearing in 2020, the different configurations and uncertainties associated with that.

We're trying to figure out what we need to do, so we have activities, and we have by the end of Phase 1, we'll have a set of assumptions and understanding on how we're going to do the 2011.

Net Short is a measurement component. Last year, we depend and we worked very closely with the RETI. Our plan is we are working with CEC this time, as part of the IEPR, CEC is working, and we are looking at the Net Short discussions, the ranges coming from 28 to 53 terabytes – terawatts. I guess that seems to be the range, I guess, under discussion how we work that out, we are still in discussion, and by the time we finish our Phase 1, we'll have a set of assumptions and how we're going to move forward with that.

Another, from a component where we have – we understood from the 2000 [sic] work was, how we do the study really has, of course, an implication or identifies what the final transmission is going to be. And the key component here is, when we do put renewables in the system, something has to give, so some of the existing fossil fuel generation has to be dispatched out. How it is dispatched out is really a major component on economics, on the environment, whether they are in-state, out-of-state, that has a major component, so we are spending a lot of time trying to understand how the re-dispatching is going to occur on the existing generation where more renewables are coming in the different parts of the state, or out-of-state. From a study point of view, maybe it’s a little too technical here, but we do have various system issues we look at from a set state, the dynamics, and many issues. At times, we cannot really do all the things you have to do, so we are considering maybe a way to handle the work, it’s pretty extensive work we have to do, so we are looking at how we do the dynamic stability analysis and how to approach that process. One key component here, of course, is a TEPPC, that is another entity within the WECC, the Transmission Expansion Policy Planning Committee. We are being approved as a member of TEPPC in February, so we are officially a sub-regional group right now, and we have a major activity on the coordination aspect with TEPPC, and that is also a component on putting the timeline, how we interact the data with TEPPC, and all that activity is ongoing right now and that is one work we are working on, the Phase 1.

So this is leading to what we’re going to do in 2011, a continuation of what we’ve done in 2010, and we’ll definitely be interacting with people. Before I finish, I just want to say – I want to invite, we have a stakeholders meeting, in fact, we have one stakeholders meeting coming up on the 19th through WebEx, and really encourage people to participate, go to CTPG.US, that is the website where you can find all kinds of information with activities on CTPG. Thank you.

CHAIRMAN WEISENMILLER: Thanks very much for coming and for the presentation. I have a couple questions. I'll start out with the observation that people sometimes miss, is that the Governor's goal is not 33 percent, I mean, that's not the ceiling, it's the floor; and certainly the way he articulated his goal was 20,000 megawatts, 12,000 distributed gen, and 8,000 utility-scale, regardless of what that means in terms of percentages. So, just in terms of making sure people realizing the magnitude of what we're trying to do, and certainly we want to work with you on OTC questions, particularly as we move forward in this IEPR.

I think the thing that was really encouraging on CTPG was that it's sort of -- first, it's historic in the sense of getting all the IOUs and POUs in one place, and one planning unit. And so I'm sure there has been a lot of back and forth through the year, but certainly congratulate everyone for getting this far, and we look forward to moving forward next year and continue to build off of stuff. It seems like some of the key questions are, as you indicated, last year you were able to build off a lot of what this agency did through RETI as a stakeholder process, and I know when I've talked to the FERC officials and Commissioners in the past, it seemed like their priority for you last year was just to go through that sort of IOU, POU planning dynamic, but realizing over time this group really had to evolve much more – I don't know if you're going to go for FERC 890 certification, or whatever – but to have a much more robust stakeholder process and, as part of that stakeholder process, certainly to bring in more of the state in terms of Energy Commission and PUC. And it seemed like you, as the ISO, are also challenged with making sure your stakeholder process is robust enough that it provides a mechanism for the independent transmission organizations to also participate. So, what is the game plan going forward in terms of getting to a much more robust stakeholder process, involving the State Government and also involving independents?

MR. BESHIR: As you said, I guess the focus last year was really working those dynamics between the IOUs and, you know, the POUs, that really took a lot of effort, now that we have a master [inaudible] that I guess I can say. We also worked on the stakeholder process. Of course, RETI was very helpful in establishing some of the early work we needed to do in the stakeholder process. Now, we have pretty robust, I would say, stakeholders; we have our own mailing list, we have also – you know, people are really accustomed to going to our website, we do have pretty active participation from many members and many entities into discussion. We do see the comments we are getting from all over, including the State agencies, and from the different independents. A couple things we have done, in addition to the outreach and the stakeholder process that exists, we have Executive Committee meetings and that Executive Committee meeting, we have made it open starting in January of this year, so it’s an open discussion, so anybody could come to the Executive Committee meeting and discuss their issues and hear what the discussions are, and input through the process. So, that we have done and we’re moving forward with that process. So, I think we will learn as we go and, if there is more that needs to be done, we will probably provide that, but at this stage, we do feel what we have provided seems to be from the reaction and the response we are getting, it’s really meeting the requirement at this time. But, of course, there may be some improvements we need and we’ll go through the 2000 process and, if there are shortcomings, we will understand they will move forward, but any suggestions you have, we're willing to accept.

CHAIRMAN WEISENMILLER: In terms of the – I would say Executive Committee – are there any State officials or independents on that, or environmental groups?

MR. BESHIR: No.

CHAIRMAN WEISENMILLER: And switching gears, the other question is, in terms of – could you provide us a list of the high potential projects that you've identified, which are not in the CAISO plan?

MR. BESHIR: I will do that. I guess the report we have is pretty extensive, but we can go through, we have a table which has all the high potential and I will make that available for the record.

COMMISSIONER PETERMAN: And also, when you do that can you also note which ones are POU projects and POU balancing authorities?

MR. BESHIR: Sure, will do.

CHAIRMAN WEISENMILLER: Thanks for your participation. And, as I said, thanks for getting this group this far and looking forward to CTPG continuing to move on and to evolve.

MR. BESHIR: Thank you very much.

MS. KOROSEC: Next, we'd like to ask our panelists to come up to the table and we'll begin the panel. Judy?

MS. GRAU: Okay, I don’t have any specific remarks, I’m not serving as a moderator, per se, but I just wanted to briefly introduce the folks we have around the table. First, representing the investor-owned utilities, we have Jon Eric Thalman for Pacific Gas & Electric, Bob Woods for Southern California Edison, Will Speer for San Diego Gas & Electric, and then from the publicly-owned utilities, we have Stephen Keene from Imperial Irrigation District, Mo Beshir, again, now representing Los Angeles Department of Water and Power, we have Lorenzo Kristov from the California Independent System Operator, and Anne Mills with the California Public Utilities Commission. And, again, we have asked for opening comments of no more than 10 minutes, and then we’ll take questions from the dais, and then folks in the room, and anybody on our WebEx. So go ahead with that. We ask our panelists to remain seated and if you do have slides, we will pull them up for you. So, I believe Jon Eric will be starting and he does not have any slides. Is that correct?

MR. THALMAN: Yes.

MS. GRAU: Okay.

MR. THALMAN: Great, thank you. Thanks for that instruction, I wasn’t sure whether to stand or sit.

Thanks for the opportunity to make comments and to participate in this workshop. As has been mentioned, a lot of progress has been made since the early, you know, the beginning days of RETI, and before that, and PG&E wants to acknowledge that there has been a lot of work and coming together to get us to the point we're at today, and so we are in a good position in regards to our environmental goals and the RPS standards.

I guess I would like to couch my remarks with a metaphor that I can't take credit for, but I think our effort as a state to get to where we want to go with our RPS goals is kind of like a person putting on a shirt, they're beginning to button the shirt, and they're very focused on getting those first couple buttonholes correct, and if they don't pull back and look at the whole picture, there's a good chance they're going to get down to the bottom of the shirt and realize that maybe they're putting the wrong buttons in the wrong buttonholes. To date, we've focused very – in a very focused manner to get the renewable resources connected to the Grid, and I think we're in a much better position today, as has been highlighted by the ISO and others, that that looks like we're going to be able to get the 33 percent connected to the Grid. I would like to propose that those are the first couple buttonholes. We need to focus on where we are in the big picture. When we get to the bottom of the short, are we going to be matched up?

And I think there are a couple of assumptions and topics that have been touched on, that we'd like to highlight here. Mr. Picker, you pointed out we have a decision to make as a state, are we going to be exporting or not? A lot of the scenarios that have looked at kind of those further buttonholes are focused on some assumptions on whether we're going to be exporting. If you look at some of the analysis and the operability of the system, not just can we get the renewables connected to the system, but can you operate the system? Those assume that we are exporting large amounts of power to the rest of the WECC. I'm not so sure that the WECC is going to want our renewables, they might, and they might not. They have their own processes where they're looking to take care of their states' issues. That's a key assumption we need to look at. The reason that that's key for the state is – and I will reference one slide that I'm not providing, but it has been provided by the CEC, if you look at the projects that are proposed to date, the progress that we have made, there's something that should cause people to question; there's a large amount of renewables in

Southern California, and there's not a lot of identified transmission to get those renewables up to the northern part of the state, so we are assuming as a state that we have sufficient transmission to operate the system with a large amount of renewables and to get it to the northern load. The assumption of exporting renewables is key to that. You're exporting to the WECC instead of running the renewables up to the state, up to the northern part of the state.

The second key assumption we'd like to highlight is something that the CTPG showed in last year's studies, and that is, yes, it's important where you connect the renewables, but probably more important from a transmission perspective, beyond just connecting the renewables with transmission, is what you're going to retire. The resources that you retire have a large impact on the transmission that is needed to operate the system. Currently, as Mo pointed out, that question involves what's going to happen with once-through cooling units, what is going to be the loading order, how are the markets going to operate? I know that's something the ISO is focusing on.

To date, we haven't fully addressed that. We continue to use different – if I say back-down principles, or research assumptions around what will happen with the once-through cooling units, and that is driven to a large part this policy of standing back and saying, “Let’s wait and let’s see if we’re going to need more transmission to connect the state north and south.” I’d like to propose that we need to – the IEPR process and the further ISO studies, and the PUC, that that’s an area we should focus on. As was pointed out, and as everyone knows, lead times in building transmission are long and if we don’t begin to address those issues today, then we very well may get to the bottom of the shirt in 2020 or beyond and realize that we do not have adequate time to build the transmission we need. Thank you.

CHAIRMAN WEISENMILLER: One of the things I guess I just wanted to follow-up on, it seems like the issue we’re facing, in part, is we’ve got one silo on generation and one silo on transmission, so we’re trying to connect those silos better as part of this process. And it seems like one of the areas that it connects is through the resource adequacy determinations, and so that gets to the issue of what are we doing on the resource adequacy issues between the Southern California Units and the Northern California PG&E units, particularly the ones that are outside of the CAISO balancing authority. Do you want to discuss that issue for a second?

MR. THALMAN: What is the particular –

CHAIRMAN WEISENMILLER: Okay, well, basically does PG&E see issues from resource adequacy determinations in its procurement contracts, given generating units in Southern California, including those outside the ISO balancing authority?

MR. THALMAN: We have concerns that will the current RA structure be sufficient with a large amount of renewables. There are assumptions in the studies and the market analysis that, you know, assuming you'll have those units there, is it economic? That would be my response. I'm not sure I'm fully addressing or understanding the issue –

CHAIRMAN WEISENMILLER: Yeah, I'm trying to figure out in terms of one of the things we need, I think, looking at – obviously, my focus is very much is in getting the ARRA projects interconnected, and one of the issues that's emerging on the ARRA Project interconnection is resource adequacy, and I think that is an area where, as we're buttoning the shirt up, we're discovering some of the buttons aren't aligning, and it's time to rethink some of that, and I guess I'm trying to figure out where PG&E is on the rethinking.

MR. THALMAN: I don't know that I have

particulars on that, but I think we're looking at that, it's certainly part of the complete picture.

CHAIRMAN WEISENMILLER: Okay, well, certainly in your written comments, if you can address the specifics there of what we need to do to enhance the resource adequacy issues for projects in Southern California. As you said, given the split for PG&E between the north and south, between many of the projects being in the south, and most of your load being in the north around the Bay Area, what do we need to do there? And also, I guess the other thing to address more is sort of, as you indicated, one of the questions is interconnection between the north and south, and so I think we've struggled for a long time on some of the upgrades, Path 15. But exactly what – where does that fit in the priority queue of going forward on transmission?

MR. THALMAN: Okay, the second part of your question, again?

CHAIRMAN WEISENMILLER: Okay, in terms of trying to identify the key transmission projects, obviously PG&E's focus on transmission has been much more going north to BC, and I'm trying to understand the relative priority between that and basically strengthening the north-south connections within the state.

MR. THALMAN: Okay.

MR. PICKER: Actually, my question is somewhat along similar lines. The Commissioner asked about differences between the CAISO plan and the CTPG plan, and I looked a bit at the Central Valley because of the increasing amount of solar that's being considered in Western Kern County, and potential that they're going to be constrained from reaching northern markets and constrained from meeting southern markets, and I notice that CAISO really has a long vehicle planned in the Central Valley all the way from West Kern all the way to the connection to the south Contra Costa networks, but that CAISO only really looks at the Borden to Gregg leg. What do we take from that? What do you take from that since it's in your service area?

MR. THALMAN: Our approach on that, or understanding on that, is that the ISO is taking a measured step, they're looking at it one step at a time, and they're looking at – Neil Millar pointed out, they have a large interconnection queue and I think when you get the geographic location for that, you'll see that there's a large amount of that queue that is in that Central Valley area. The certainty to what extent that will develop, they're hesitating to approve more projects, and so the Borden-Gregg line work is an indication of how confident they feel on that. Our urging to them is that that, combined with the operational needs to move power up and down the state justifies moving forward more projects in that area. If we pull back and we look at from a state perspective, meeting the RPS targets, what percentage is going to be driven by -- the cost of this goal is going to be driven by the energy purchase price, and what cost will be driven by the cost to build the transmission, and then the prospect that prices can be influenced by congestion and lack of transmission, that we believe it’s warranted to move quickly. That, added with the fact that the construction times we’ve talked about.

MR. PICKER: Well, you make some discrimination when you assign contracts with projects, do you have more confidence in your ability to make an economic decision about who you contract with than, say, CAISO or CTPG? Which do you have more confidence in, in terms of helping us to shape our future decisions about where and how much and when we need transmission?

MR. THALMAN: I think we look at it from a strategic standpoint and you control the variables that you have within your shop. I’m not so sure I want to speak for our energy procurement group on that topic.

MR. PICKER: This is a challenge because some of the projects that we see at risk because of the lack of timely transmission are both subject to decisions made by the transmission side of a utility and the procurement side, and clearly there is a firewall between them, but it seems like even there, we ought to have better ways to make similar kinds of decisions in the interest of having more buttons buttoned together as we go up our shirt.

MR. THALMAN: I think we agree.

COMMISSIONER PETERMAN: Hello. I want to make sure I understand your reference to the assumption in our scenarios that we're exporting to the WECC. And so can you clarify why you brought it up? It was done in connection with talking about the assumption also that we have transmission to the north. Was there a connection there? Or were you just stating that those were two assumptions that we have?

MR. THALMAN: I don't think there's necessarily a direct connection to them, it is part of the overall picture. The point I'm trying to point out is that, when we look at a whole WECC integrated operating type of a study and we say, "Will this work? Will we be able to operate this system," then invariably we end up exporting a large amount of – assuming the large amount of resources in the southern part of the state are exported to the WECC and do not move up north through the state, and that assumption then leads to the result that says, “Oh, it looks like we’re okay, we do not need a backbone transmission up and down the state.”

COMMISSIONER PETERMAN: And then, is the expectation that the renewable in the north is met with generation in the north or imports?

MR. THALMAN: A combination of both. It ties into the second point I had, and that was what are you going to back down? In those scenarios, you end up not backing down as much of the traditional resources in Northern California. Yes, you still are importing from the northern part of the U.S. from the Northwest, but for the most part, the difference is the fact that you back down more resources in Southern California and you’re relying on a larger percentage of the renewables to feed the load in Southern California, and in a sense, Northern California continues – if you really looked at the flow of the electrons, but that’s not our goal with our RPS target, but you’re assuming that that’s how it’s going to work – and it might work that way, but that’s the assumption.

COMMISSIONER PETERMAN: Thank you.

MR. WOODS: Good morning. I’m Bob Woods with Southern California Edison, Director of Electric System Planning. And what I would like to talk about this morning are the challenges and then the progress and the recommended actions. First, let me thank Chair Weisenmiller, Commissioner Peterman, Mr. Picker, Mr. Feist, thank you very much for allowing us the opportunity to provide input to this process.

In terms of challenges, the first thing I would like to look at is the system operability and, within that, safety and reliability primarily resulting from intermittency and the lack of real time control of some of these generation resources. The impact of generation on our ability to actually operate the system by transferring load between circuits and substations is a concern to us, as well as unintentional islanding, which results – well, has been seen in Spain and results from a large concentration of generation resources in an area that exceeds the traditional generation and low loading.

In the past, we've had a lot of spinning generation, turbines and such, and there's a concern that the new type of generation will not have this ability to ride through temporary faults, and the concern is that we may drop large portions of generation quickly. And that will, in fact, result in effects to our voltage. What we want to try and do, of course, is maintain steady state voltage regulation and the intermittency of generation coming on and dropping off will present some challenges to maintaining that steady state voltage regulation that we have in the past.

In addition, we want to make sure that when we put our workers on the line, that we can clear the lines and be assured that they do stay cleared and safe for our works.

Another concern is, when you add a lot of generation to a particular area, really, almost any generation, you can create short circuit duty which is basically the rating of the equipment to withstand faults, and in some cases we have seen where the addition of generation has resulted in the overdutying of circuit breakers and we’ve had to change those out to a higher rated circuit breaker which ultimately results in costs. A concern that we have will be power quality, we’re not sure if the new type of generation will introduce harmonics and how we deal with that.

Traditionally, when we built our system, we built it generated and we started with the big wires all the way out to the small wires on the end. Today, that is shifting. We can connect generation almost anywhere, and it will result in some potential changes to the way we design our system, the way we operate our system, and also the way we try to protect our system.

Another concern of ours is the interconnection costs, both from a developer perspective and a utility perspective and, of course, the resulting impact to rates. The interconnection process itself, of a particular challenge to Edison, is the fact that we have 865 renewable interconnection requests in the queue today. This really does have resource implications for me, personally, in terms of power system planners and distribution engineers, the ability to get this work done and meet some strict guidelines. Another thing is land use. As Mr. Picker indicated, projects are taking a long time and there is a concern that our current requirement to hold land in rate base for a certain period may be slightly outdated, given the current requirements that it is taking.

Over on the progress, there has been progress, there has been considerable progress in the process. The large generation interconnection process, going from a serial study to the cluster study, has improved things tremendously. Taking that to the small generator interconnection process has also helped, the recognition that enough small generators could impact the system similar to a large generator has been a big help, and I think will yield tremendous progress in the future in terms of assessing the overall impacts to the system.

As far as major SCE transmission projects, we have been working with the Governor’s Office, the State and Federal agencies, and CAISO. We provide regular updates in the form of bi-weekly conference calls, one-on-one meetings, things like that, regular quarterly meetings with the ISO where we review our projects, review the progress, and I’m happy to say at this point there really are no red flags in the major projects that we’ve reviewed.

In terms of recommendations and streamlining the permitting process, we have stated before and we continue to believe that the greatest time savings are from those projects that CAISO identified as approved by ISO, but not yet permitted because we think that the newer processes are going to be better than the previous processes, and we will continue to move forward. We do support reforms that reduce the overall permitting times and believe in the non-Legislative approach. We do think one of the biggest impacts to the whole process has been the increasing collaboration that’s occurred between the State and Federal agencies, and the applicant before, during, and after the application process, trying to avoid duplicate analysis surveys, but yet still manages to maintain agency independence. We do support conformance of the legal agency imposed mitigation measures to make sure that they match the measures required by the resource agencies. We believe information requirements and detail levels in CEQA and NEPA documents should meet, but not significantly exceed, the legal requirements. That's it.

CHAIRMAN WEISENMILLER: Thanks. A couple questions, one of them was, comparing the generation permitting process here and the transmission permitting process at the PUC, the Energy Commission has the functional equivalence process on CEQA, the PUC obviously has the standalone CEQA and CPCN process, and I guess we're struggling with lessons learned to understand whether the functional equivalence or how much that accelerates, or doesn't, but in terms of – has Edison given any thought to whether that sort of process might help in the transmission part?

MR. WOODS: I'll be honest with you; I'm not that involved in that aspect of it, more the planning end, so I'd be happy to provide a response to it, put it in our written comments.

CHAIRMAN WEISENMILLER: Okay, that would be good. The other question, I noticed in terms of – in the streamlining, is you don't mention DRECP, and again, that's certainly where we lost Commissioner Douglas today as we try to push that forward with at least the hope that that's going to help on streamlining the permitting processes.

MR. WOODS: I didn’t mention that specifically, but I do believe that is part of the collaborative process that we talked about. And as we talked about last week, the hope of using something like that process to develop a more collaborative approach to identifying the transmission corridors that may be required in the future, and preparing well in advance.

CHAIRMAN WEISENMILLER: Okay, and for this group on the record, I mean, in terms of the ARRA interconnection projects, which are you most concerned about in terms of the timelines?

MR. WOODS: I’m not sure, well, I think anything West of Devers is probably an issue, or getting power from east of Devers through West of Devers is, of course, a concern of ours. There appears to be a choker there and we are, as I think most people are aware, we are negotiating with a number of agencies trying to expedite that process. But we do believe that we can meet our commitments, what we have done is we’ve worked with CAISO to try and develop an interim measure, which will facilitate connecting generators sooner.

CHAIRMAN WEISENMILLER: Okay, and does Edison have any suggestions on how the resource adequacy approaches could be enhanced or improved going forward?

MR. WOODS: I'm sure smarter people in Edison than me can provide input into that.

CHAIRMAN WEISENMILLER: Okay, so will you hit that in your written comments also?

MR. WOODS: Yes.

CHAIRMAN WEISENMILLER: Okay, thanks.

MR. PICKER: Very quickly, I want to thank the SCE transmission staff for their extraordinary efforts to help expedite the conclusion of large generator interconnection agreements last year, to be able to help projects to qualify for financing under ARRA and other government financing programs. I also have to say that staff is working very hard to develop tools to expedite the permitting of projects. I think the challenge that we still face, even if as we gain efficiencies by coordinating better in the permitting process is the front end where people form the intention as to where we're going to build new transmission. And so I think that we will have to all work together to improve that. But I do want to thank you for the hard work of your staff in terms of actually improving some of the back-end planning and approval processes.

And so, out of the 865 interconnection requests you have, could you quickly characterize which – what number actually within your distribution grid and which are large-scale projects? I would be surprised if you have 865 projects over 200 megawatts trying to connect.

MR. WOODS: I couldn’t give you the exact numbers, but you’re right, a large portion of them are down at the distribution level which, again, do require significant resources, but I couldn’t give you the exact breakdown. If you’d like, I can provide that –

MR. PICKER: At some point, it would be very handy because we are starting to see a whole set of different kinds of challenges as we try to figure out how to interconnect 12,000 megawatts within the distribution grid, and I’m curious to see what kind of workload you already have. So, thank you.

MR. WOODS: Absolutely. And I’ll pass on the comments. Thank you.

COMMISSIONER PETERMAN: I would just echo Mr. Picker’s interest in seeing that breakdown, the different types of projects, particularly interested in the distributed generation side, and in terms of Edison’s CSI procurement to date, it’s lagging a bit in steps behind the other utilities, and so I was just curious to see if the interconnection was one of the issues driving that.

MR. WOODS: I don’t know for sure, but we can certainly check into that. Thank you.

CHAIRMAN WEISENMILLER: Thanks again.

MR. SPEER: Good morning. My name is Will Speer from San Diego Gas & Electric. I would also like to echo my colleague’s comments. We appreciate the opportunity to speak here today. I took a little different approach, I’ve kind of looked at the projects that we have ongoing today. Everybody is familiar with the Sunrise Powerlink, but I wanted to highlight some of the challenges in licensing and some of the obstacles that we overcame. As you see, it was a four-year process, so we need approval from CPUC, Bureau of Land Management, and United Forest Service. We had over 43 – and I noticed there was a little missing a word there, but over 43 public hearings just getting this project licensed, 11,000 pages for the Environmental Impact Report, the largest in California’s history.

Additionally, we implemented 320 environmental and cultural mitigation measures totaling a thousand separate tasks, so it’s ongoing, it’s a very difficult process. We also purchased 9,300 acres of habitat mitigation, which is one of the largest land preservation efforts in the region’s history. We are proud to say construction is underway, we have the towers going up, it’s moving along, we are looking for an in-service date next year, so I appreciate everybody’s support on this project, it’s vital to the future.

Another large project that we’re undertaking right now is Eco Substation, it’s in Jacumba, it’s going to eventually be a 500 230 to 130 AKV Substation. It’s main goal is the same kind as Sunrise, it’s to integrate renewables. Obviously, we’re familiar with the availability of wind and solar resources in the Southwest area, so this will be another substation that, when we get it approved and constructed, will bring resources into the California ISO.

We are in process right now. We haven’t been approved for everything yet, but as you can see from some of my bullets, that we applied to CPUC in August of 2009, we got notice to prepare our environmental impact report in December 2009, we’re expecting for a final decision in the fourth quarter this year, and we’re hoping for a 2013 – we’re targeting 2013 in-service date.

The other slide I’ve got here is – this is a pretty busy slide, but I figured it does a pretty good job of showing what we’re all up against. This is kind of – this is our picture – these are through Cluster 3 of the projects that will want to connect in the southwest region. A few years ago, all we had here was

Imperial Valley to Miguel, the 500 KV line. As you can see right now, I think this slide does it justice, what we’re up against, but currently there’s over 4,000 megawatts of solar that wants to connect on IV 230 bus, the Eco Substation I mentioned has 1,140 in the cluster to connect. Hassayampa-North Gila has another 2,400 megawatts of solar. So, within cluster 3 alone, it’s 5,500 megawatts. When you add the recent cluster 4 projects, it’s 6,300 megawatts that want to connect to SDG&E. And our peak for 2020 is 5,600 megawatts, so definitely we’ve got a challenge. We know all these projects aren’t going to come to light, but we figure – our plan is with some of this infrastructure built, the Eco Substation, obviously Sunrise Powerlink, some of the work we’re doing on Imperial Valley, we’ll be able to bring this generation to the California ISO.

The only other piece I had, I know you guys are interested in the RA deliverability question and we echo the response of everybody else. I think it’s a concern in the future. I know the issue is how do these renewable resources get RA credits, and obviously it’s worth – you know, they need RA credits to be viable, so I don’t have an answer for it, I think it’s something that all the utilities need to work on together with the CAISO and try and improve the process. So that’s all I have.

CHAIRMAN WEISENMILLER: Thanks. I guess the question I have for you, when the Sunrise Powerlink decision was voted out by the PUC, the PUC was struggling with the question of how to focus its use by renewables, I mean, a variety of different decisions. And I think you were directed to do some outreach and to do some special procurement. How has that worked out, and just in terms of –

MR. SPEER: It's working out well. Given the location of Sunrise and, you know, the vast amounts of resources in the Imperial Valley area, we've been pretty successful so far. We've lined up contracts with developers and the process is working, so….

CHAIRMAN WEISENMILLER: I mean, what sort of loading do you expect on the line from renewable power at this stage?

MR. SPEER: Most, if not all, I believe. I mean, obviously it's connected into the Grid, so we will schedule enough power to get over the thousand megawatt rating at this point, but obviously it's interconnected, but we will secure contracts just to meet that.

CHAIRMAN WEISENMILLER: Okay. And in terms of the RA interconnection projects, I guess there are a couple that involve you? I just wanted to check on their status.

MR. SPEER: I’m sorry –

CHAIRMAN WEISENMILLER: I mean, in terms of the ARRA projects that we approved, I think particularly Calico and some of the others involve SDG&E, and I just wanted to check on the status of those interconnections.

MR. SPEER: Most of them are moving along. I brought the list with me, too. I think we’re doing well. At least half of them are moving along pretty well. There’s been some challenges on the developer side with some of those projects and some of them not coming, other issues on their end and their permitting and the problems they’ve encountered, but overall it’s been working.

CHAIRMAN WEISENMILLER: Okay, it sounds like even the ones that have problems, given the nature of the queue here, you have your back-up projects for that capacity.

MR. SPEER: Yes. We have ample amount of resources in that area.

CHAIRMAN WEISENMILLER: Okay, thanks.

COMMISSIONER PETERMAN: I would just say I really like this slide, by the way, showing the transmission. It’s actually surprisingly intuitive. And what did you say the total expected megawatts from the Cluster 4 study?

MR. SPEER: For SDG&E, it was 6,300.

COMMISSIONER PETERMAN: Thanks.

MR. KEENE: Good morning. My name is Steve Keene, I'm Assistant Manager for Policy and Regulatory Affairs at Imperial Irrigation District. I'd like to thank you for the opportunity to appear here as a panelist in this morning's workshop. IID believes that Imperial Valley renewables are going to be a key to helping the state meet it's 33 percent and beyond RPS goals.

As I'm sure you are aware, there's a great deal of activity and renewable development in the Imperial Valley right now. Currently, we have 44 projects in our interconnection queue representing over 3,000 megawatts of renewable energy. The breakdown by resources appears in the slide there because you can see a great deal of solar and geothermal, a little bit of biomass. Currently, we don't have any wind in our queue. We have also transitioned to a cluster interconnection process and our first transitional cluster is nearing the end of that process, and that transitional cluster has 13 projects with 1,225 megawatts, all of which is seeking delivery into the California ISO. The facilities studies for that transitional cluster have identified

$300 million worth of upgrades to our system. Most of that, about $275 million of it, are net work upgrades for which the generators will up front those costs and then be reimbursed with transmission credits. About $25 million of the $300 million are directly assigned costs for the gen-ties.

We have recently on May 3rd tendered the Generation Interconnection Agreements to the transitional cluster customers, and we're in the process now of finalizing those interconnection agreements with a targeted execution date of June 16th. The preliminary indication from the developers in the transitional clusters is that they all intend to move forward and the proposed in-service date for those upgrades that were identified for this transition cluster is December 31st, 2013.

Now, the transition cluster identified certain upgrades, the first of which is the Path 42 upgrade. This was a joint project with Southern California Edison and it's a result of two years of work that we've done with the California ISO, Southern California Edison, and the CTPG process, and I think it's a good example of a POU and an IOU working together on a joint project such as this. And as you know, the SCE upgrades to Path 42 are part of the California ISO's transmission plan that’s going to their Board this week. Path 42 is a reconductoring of an existing line and the preliminary studies indicate that it’s going to increase our deliverability into the ISO by about 855 megawatts. Another of the transition cluster upgrades is the Highline to El Centro line and this is an upgrade of an existing 92 kv line to double circuit 230 kv. When this is completed, it will, along with the IV to El Centro upgrade, we will then have a complete double circuit 230 kv path from the Imperial Valley Substation, which is our SDG&E intertie, to the Mirage Intertie with SCE.

Another of the transition cluster upgrades is the Midway to Bannister Phase 2, and this is an additional 5.5 miles. Phase 1 was an 8.5 mile segment of Midway to Bannister, and that is now completed. Phase 2 will extend this line an additional 5.5 miles, and Phase 3 will ultimately extend it another 16 miles to interconnect with the new Bannister substation on our L line on the west side of the Salton Sea Resource Area. And in addition to the transition cluster upgrades, IID is also in the process of building the Imperial Valley to Dixieland 230 kv line. This is a reliability project for IID, but it will also allow us to increase our export capability at IV by more than 300 megawatts. So that’s the status of the transition cluster and the upgrades associated with it.

I'd also like to take a few moments to briefly address the resource adequacy issue because it's come up several times this morning, and this has been an issue that we've been wrestling with for over the past six months, and I've had numerous meetings with various people, many of whom are in this room today, some are even on this panel, and it's a vexing problem for renewable developers, interconnecting to the IID system. Currently, there's insufficient RA import capability available at the IID interties with the ISO. It does not allow for deliverability of renewable resources from the Imperial Valley. The RA imports are undervalued or else they're not available at all, as it is the case with the Imperial Valley Substation, where the RA -- or the current maximum import capability is set at zero. And this is because of the methodology that the ISO has relied upon, which looks at historic schedules, and the Imperial Valley Substation IID is a net importer from the ISO, therefore, when you look at the historic schedules, there's been nothing being exported to the ISO and the RA is set at zero at that intertie.

The insufficient RA import capability at the IID interties limits the use of IV renewables to meet the LSE's RA requirements. We believe the CAISO's proposal to amend the methodology utilized to calculate the maximum import capability for RA goes a long way towards addressing this problem for IV renewables. But our primary concern at this time is that the proposed change in the methodology is going to take some time to be fully implemented. And it may take until the spring of 2012 until a revised MIC is posted for the IID interties. In the interim, the LSE’s will be undergoing an RFO process for renewable procurement this summer. In addition, ongoing bilateral negotiations for PPA’s are expected to take place throughout the rest of the year. The LSE’s procurement personnel have told generators that they cannot sign a PPA with IV projects until the final revised MIC is posted. So, for the rest of this year, that number of zero at the Imperial Valley Intertie is going to remain until the new methodology kicks in. We should all be striving to ensure that the Imperial Valley projects are not excluded from the upcoming RFO process and other procurement opportunities that may take place this year. These are projects that are located in a highly ranked CREZ within the State of California, and include a great deal of baseload geothermal energy. They are resources that could be accessed through relatively inexpensive transmission upgrades to the IID system, utilizing existing transmission lines and corridors, with minimal environmental impacts.

Development of these resources is vital to the economic recovery of the Imperial Valley, that will bring much needed, well-paying jobs to an area that desperately needs it. And thank you.

CHAIRMAN WEISENMILLER: Thank you very much for participating today. I would say that I know one of the high priorities, certainly for this Commission and certainly for the Governor’s Office, is in fact to achieve that economic development potential in Imperial Valley through the renewables, to provide – I know when I went through the Blythe cases, the unemployment rates in that area are very high, you know, and it was certainly one of the ways to try and deal with that is through the renewable development, so bottom line is, in this document, to put a high priority on addressing the resource adequacy issues so that we can develop the renewables in Imperial Valley and then have that marketed to the rest of California. Obviously, there’s always balancing the public policy, but your area is a region that needs that economic development desperately and certainly we need the renewables from there as part of our mix.

I think – I was going to step back for one second, I forgot to ask the gentleman from SDG&E the status of the – one of the things we're looking at today is independent transmission, so what is the status of the citizens participation in Sunrise?

MR. SPEER: It's in front of the CPUC today. We don't have – we have a proposed and an alternate decision, but I'll have to get back to you on specifics.

CHAIRMAN WEISENMILLER: Okay, and how long has it been there?

MR. SPEER: I will have to get back to you.

CHAIRMAN WEISENMILLER: Okay, that's fine. So, on Imperial, sorry, getting back to you, actually one of the issues that you really raised in the Sunrise case, Imperial Valley, IID did, was the concern that Sunrise might encourage bypass of your system through direct connects. I was wondering what the current status of that was.

MR. KEENE: Well, the position that IID took in the Sunrise proceeding was that we were supportive of the project. We differed with SDG&E initially on the proposed route; their favored route was called the Northern Route and it kind of skirted up through the eastern side of our service territory, and then crossed the mountains through the Anza-Borrego Park. That particular route came dangerously close to the Salton

Sea Resource Area and would have presented a great threat of bypass at the IID System. Currently, IID has 1,000 megawatts of excess capacity on its KNKS line. All of this transition cluster is going to benefit from that excess capacity because that's 1,000 megawatts on the KNKS path that they do not have to build. So, we were concerned about a Sunrise route that came too close to – or, really, cut through the heart of the IID's system and created a risk of bypass. Ultimately, the route that was selected, and the route that is being built right now, is the southern route, which essentially parallels the southwest Powerlink. That route does not really present a threat of bypass to us, the ISO and San Diego Gas & Electric area already there and they have the southwest Powerlink. So, we were supportive of Sunrise as a necessary transmission line to export IV renewables, we were just interested in which route it was going to take, and we are satisfied with the route that was ultimately chosen.

COMMISSIONER PETERMAN: What is the status of network upgrades and transmission planning for the about 1,900 megawatts that were in the transitional cluster?

MR. KEENE: Well, what's in the transitional cluster now is only 1,225 megawatts, the upgrades that I just outlined this morning are those upgrades necessary to the IID System to accommodate that 1,225 megawatts.

COMMISSIONER PETERMAN: And so the difference of about 1,900 to get to the about 3,100 of the total projects you have, have those not been planned yet?

MR. KEENE: No. Those will be studied as part of the next cluster.

COMMISSIONER PETERMAN: Okay.

MR. KEENE: Or, actually, there's three other clusters behind this transitional cluster, and that's where the 1,900 are spread out among.

COMMISSIONER PETERMAN: Great, thanks.

MR. PICKER: Help me try to understand this a little bit. You expect around 3,100 megawatts of new renewable generation to move forward through the process in Imperial, and how does it get out of Imperial? I mean, your peak demand in Imperial is significantly higher than that, and you already have generation in place, and so I know that there's an effort underway to expand the existing 600 on Path 42 to roughly 1,200; SWIPL is almost fully subscribed, and then how much is going to go out through the Sunrise Powerlink, and where do you find yourself completely bottled up? That's the first question, is do you think there is adequate capacity, transmission capacity, to be able to move this power out of Imperial? And where do you see the bottlenecks?

MR. KEENE: Well, we're confident that we can build the transmission necessary to deliver at the ISO. Whether the ISO can receive it is really an issue that would have to be addressed through their planning process each year. Right now, I think that they are prepared to receive the 1,225 megawatts that's in the transitional cluster and future clusters would have to be studied in their future transmission planning years.

MR. PICKER: And so what happens after it gets to CAISO? Do you have any sense of the bottleneck that Mr. Woods was talking about at West of Devers for power that's coming north from Path 42? What does that mean for –

MR. KEENE: Well, we are aware of the West of Devers bottleneck and we – there is some interim solutions that are part of this year's transmission plan, is my understanding, and I think that there are longer range upgrades that Edison has proposed that are several years out.

MR. WOOD: Yes, we have, as I indicated, we are trying to work on an interim plan to assist and we're still in the feasibility portion of it, to come online around 2013. The ultimate West of Devers fix is scheduled more like 2017-2018 timeframe at this point.

That’s where we have to actually rebuild four 220 kv lines from Devers to San Bernardino and Vista Sub and Grand Terrace.

MR. PICKER: So, many of the utilities have multiple roles as both transmission providers and then procurers of power; do you have any sense of how confident your procurement staff are in these general plans that you have to move power? What kinds of risk do they think that makes for them in terms of contracting with these projects in Imperial?

MR. WOODS: I think the only issue at this point would be the timing and when we sign contracts, we have to be aware of the timing. But once we get those lines built, the Path 42 connection, and the West of Devers lines built, I think we have a high degree of confidence we’ll be able to deliver.

MR. PICKER: Okay. Thanks.

MR. BESHIR: Good morning again. Mo Beshir from Los Angeles Department of Water and Power. Again, thank you for the opportunity to come and discuss about LADWP’s work on this panel. I guess the discussion or the question is what other progress has been made and what challenges, so, again, the way I would like to discuss is maybe go through some of the activities and transmission development plans for LADWP, and partly we go through some of the progresses and some of the challenges we face with each of the different projects we have. So, if we can go to the next slide, going back a few years, this was really a key component of our transmission development activity to meet our long term resource issues from a renewable perspective. So the activities we spent was really to understand what are the renewables available close to our transmission lines, and how do we meet our long term renewable resource development activities. And we chartered a process to identify the different transmission developments we needed to do to meet our issues. So I’ll go through one-by-one and really identify some of the highlights, and some of the key components, and some of the challenges.

In the far north, we have the STS Transmission, what we call IPPDC Transmission Line, along that in Utah we have opportunity for large solar wind and also some geothermal activities, so early on identifying that opportunity, we in part embarked in a development and expansion plan for the DC line. The DC line opportunity for us was to increase the capacity from the then rating of 1,920 to 2,400 megawatts using new technologies and activities necessary to make that available, not only that having to increase the capacity, but also to work on technology to integrate wind so that we can dynamically schedule just wind from Utah to Southern California. So that work took a few years, happy to say that project is completed, we have 480 megawatts of additional capacity from the Utah side, all the way going to Southern California. In addition, of course, associated with that, we have 300 megawatts of wind, Milford Wind 1 and 2 integrated, we have as far as the development activities to look for additional wind opportunities, and maybe some additional geothermal in that area, and maybe further development and expansion. For the nature of that development activity from a transmission point of view, it has very little impact from the environmental perspective, so it was a pretty straightforward, the timeline. As far as the actual development of the converter upgrades were 24 months from actual spec to finishing the project, there was a contractual issue, of course, but also associated control and design consideration. So that was really the key consideration there, but there are more opportunities as we go forward for more integration of additional renewables. So, DC in a sense did provide really a good opportunity for us to expand the capability. Going on the middle, we do see as a Barren Ridge Renewable Transmission project, that is to access extensive renewables from the Tehachapi and some solar also in the High Desert. We have a project called Renewable – Barren Ridge Renewable Transmission and that consists of building double circuit to kv line, in addition to also reconductoring existing 230 kv transmission, that capability also is integration of those resources into our Castaic pump storage facilities. So, I did discuss last time I was here the integration aspects on how we plan to integrate the large solar and wind, which is coming into that area, into our pump storage facilities, and the Transmission Expansion Plan does provide that capability, to be able to do that. That project is ongoing, we are through the environmental process of the transmission upgrade expected to be in service in 2015 time period. Further north, we do have a large wind facility, as well as contracts in accessing small hydro, as well as solar wind from the northwest, and we do have one of the largest DC lines in the world, accessing – for going from Shiloh Station up in Oregon, or the Oregon Washington border, to Southern California. We are working with BPA and the different participants looking at further expansion of the project. We have tested some processes through the CTPG process to see what upgrades the system would hold. We have an opportunity to look up to 800 megawatts. We are still in the feasibility analysis with BPA and Southern California Edison, other parties who shall have ownership and participation in that transmission. Hopefully the next step is, if we do get the upgrade necessary, also to be able to dynamically schedule a bunch of the possible wind from the northwest to Southern California. In the South, large geothermal resources, but we have other larger projects previously where we were trying to access large geothermal resources; those transmission projects are not being reconfigured now. Presently, we are working with IID on the Path 42 upgrade process, we are participating in that process, and hopefully that will allow us to access some geothermal resources into the IID system. So those are really the major aspects in transmission development for us. Overall, we will meet our 33 percent or plus by 2020, our projection is we will be able to meet it with all the resources we have, with our transmission development we have on line, but also beyond what is required for LADWP, we have other SCPPA members, we jointly plan and have participation and measure most of these development activities, as well as other independents which have transmission interconnection under large generator interconnection processes to our transmission development activities. And we will be able to meet their need, as well. That’s it.

CHAIRMAN WEISENMILLER: Thank you. A couple questions, one of them is one of the ARRA projects that we permitted was the NextEra’s Beacon Project, which I believe had planned to interconnect on your system perhaps wheel through?

MR. BESHIR: Yes.

CHAIRMAN WEISENMILLER: What is the status of that interconnection?

MR. BESHIR: The interconnection work is completed. The original, of course, as you may remember, the original project was a solar thermal project, so the original work was completed, went through the facility studies, all the way with the thermal facility, so solar thermal. The current configuration is thin film concept, so we are going through some additional restudy of the project. We are almost completing that activity right now on the restudy. So, as far as from LADWP – from the study point of view, it is feasible and could be integrated. The key component there is to be able to access 50 megawatts, it would require the expansion of the transmission line. And that expansion of that transmission line is not going to occur until 2015, so it is in the environmental process to get the full tranche of 50 on top of the other – in the queue, we have a whole bunch of wind, other solar would require the expansion of the whole transmission line.

CHAIRMAN WEISENMILLER: Okay, so this could become another resource adequacy issue? If you are willing to and are selling the power to one of the IOUs to the extent that you’re at a different balancing authority, you could have issues similar to what IID has at this stage.

MR. BESHIR: We are in discussion, in fact, we just started to have that discussion with NextEra, along within the same discussion, just starting, but definitely it would be in the same resource adequacy considerations. But we do have – the delivery points which may occur for this would be a the Sylmar Station, which we have extensive capacity exchange within CAISO, where most of the DC exchange between LADWP and Edison is where that occurs, as well as the Palo Verde Power transfer between Edison and LADWP, also occurs as that transmission, so this is large transmission capacity available in that interconnection.

CHAIRMAN WEISENMILLER: And one of the issues I think I probably raised in the 2005 IEPR was sort of the level of interconnection between Edison and LADWP, it seems like generally they don't quite have moats between them, but there is certainly not a very rich amount of interconnection. Have you studied the potential for greater interconnection in the Edison – or with Edison?

MR. BESHIR: Over, I guess, periodically we do look into that, on an ongoing basis, as needs arise. We have – today we have three major interconnection points at El Dorado, at Victorville-Lugo, as well as Sylmar. So those are really the – and a tremendous power does move through those interconnection points. We have one other interconnection we call Laguna Bell, which is already continuously to be open. But we have used that for emergency purposes and because of the loop flows and inadvertent flows, we cannot really connect to that, but we continuously look at opportunities for interconnection and, as we speak, we are also going through a study with Edison looking at some of the OTC issues and some future and potential interconnection considerations.

CHAIRMAN WEISENMILLER: That's good. Yeah, I mean, my concern was looking at the OTC questions in the sort of South Coast area, trying to get more interconnections within the basin as we go forward, and the OTC context might be important.

MR. BESHIR: *Yes, we are engaged in a study* *together right now.*

CHAIRMAN WEISENMILLER: Also, in terms of any potential looking at essentially doing more scheduling on the ties, not just hour by hour, but more than 15-minute, or at least shorter periods between the different balancing authorities?

MR. BESHIR: We haven't done that yet. As we speak, starting March 1st, we have changed the configuration of Sylmar where we have put a bigger bubble where we had different Edison and LADWP Stations. Now, we are considering that, as one station, one scheduling point, so we do see benefit from being able to do that, but definitely, as we move forward to look at other opportunities, including, you know, inter-hour scheduling along the tight points.

CHAIRMAN WEISENMILLER: I'm assuming inter-hour scheduling between the – or among the California balancing authorities, if not on the interties should provide some additional economic benefits and also help with renewable integration, so I think that was one of the issues we'll certainly be teeing up as part of this effort.

MR. BESHIR: I agree. In fact, the opportunity is there because we do have some PTO's, California Participant Transmission Owners, who are within the

SCAPA family and we have joint transmission, joint generation, so we do have continuous scheduling back and forth between the CAISO balancing authority and LADWP balancing authority. So, opportunity definitely exists for that.

CHAIRMAN WEISENMILLER: Okay. Thank you.

MR. KIRSTOV: Good morning. I'm Lorenzo Kristov with California ISO. Thank you for including me in this panel. I think there are a number of topics that I can pick up on from comments raised by other parties to address specifically the question asked about challenges and what we're doing, and the progress we're making. I think the place I would like to start is just to reiterate what I think everyone knows is one of the biggest challenges is the uncertainty about what the path of development of renewables will look like, and we've been aware of that and grappling with it for the last couple of years based on the recognition that, following upon the great work of RETI, that there are many many areas that have the potential resource mix and we could build transmission to connect all of them at a very high price and have a lot of it go under-utilized, or we can take a lot of time getting the right decisions, and then we find that we've taken too much time and the transmission isn't ready when we need it.

So that’s the tension that we’re trying to really balance in everything that we’re doing as we make reforms to the processes that we have in place. Our interconnection process, our transmission planning process up until we made changes last year, and a lot of the way that we operate our markets, all of these were predicated on not having huge amounts of variable energy resources, they were predicated on building transmission to accommodate a few percentage points of load growth every year and, really, that was it, and incremental additions to the generation fleet now and then, sometimes big units, but for the most part no huge wholesale change-out in the generation fleet. So, all of those assumptions really that went into the designs of these processes have been overturned, and that’s why we’ve been struggling with different policy initiatives to change the processes, and make them work better for this new world.

In the specific context of the question regarding transmission development, I think one of the most important things is whatever can be done to narrow the range of possible areas that are going to be developed. And I think the DRECP could be an important contributor to that. There is no point in things – projects moving through the ISO process quickly getting approved, and then hitting a downstream bottleneck. We would rather be able to anticipate more of those bottlenecks up front, or siting challenges, or permitting challenges, etc., so whatever can be brought to bear. And this was a theme of a Memorandum of Understanding that ISO developed with the Public Utilities Commission last spring as part of reforming our transmission planning process, and that focused on how can we modify the ISO's planning process so that the projects moving through that have a higher chance of success in the permitting process at the CPUC, and that comes down to the extent to which we look at alternatives to address different transmission needs, and also the robustness of our stakeholder process because, through both ISO planning and the later permitting siting processes, the public engagement is a crucial piece, so we have been continuing to meet with PUC over the last many months, taking that MOU as a point of departure, and each time trying to make it more practical, implement the details of it and make it work.

So when it comes to the narrowing the broad range of locations and narrowing the uncertainty, that's really in the formulation of the generation portfolios, what do those portfolios look like? What are the ones that have high probability of success because load serving entities are signing PPAs with them, areas that we hope will become more and more clear about where the environmental challenge is, so which ones are less likely to develop and which ones more likely? And then be able to, through this concept of what's been termed "least regrets," basically you look at the options of where the generation can locate, you try and narrow that down into a few scenarios as Neil Millar outlined in his presentation this morning, and then you look for transmission upgrades that will meet the needs of more than one scenario, so that if the development over the next couple of years takes one path or another, you're still making transmission choices early on that have a high probability of being needed and minimize risks of unutilized capacity being paid for by ratepayers.

One element that we built into our transmission planning redesign last year that we're looking at again to try and enhance and make more useful is this concept of Category 1 and Category 2 transmission upgrades. In this new policy driven category where we identify public policy objectives, working on 33 percent RPS for the moment, Category 1 facilities would be ones that are identified that merit approval now because, looking across the scenarios, the range of potential pathways that the development can take, these transmission lines, we know, are substantially needed and will be useful under alternative scenarios. Category 2 are ones that may appear in one or two scenarios, but maybe not in the most likely scenario, and that we say, well, if development takes a certain pathway, then these will be needed, but rather than approve them now, let’s wait another year and revisit them. The piece of that that we were thinking a little bit more about is, is there a way to strengthen this Category 2 notion so that, when a project is identified as Category 2, it’s more than just, “Let’s look back, look at it again next year.” Is it possible to allow some work to progress on it, some of the really – the ground work that is not construction, but things related to engineering and study processes, and so on, so that if a year or two down the line a Category 2 gets converted into a Category 1, well, some of the groundwork for that has been done, and now the development timeline can be shortened. So, that’s something that we built in as a concept. I think we need to think a little bit more practically about what the difficulties and challenges are of making that a more practical and beneficial process. And then, again, the total process, I would emphasize again, is between the ISO planning process or interconnection process, and then all the way through permitting where the robustness of the stakeholder process all the way through is really critical because all of the stuff has huge public interest.

Let me go into one element that was – and we are identifying innovations where possible that meet specific problems, so in the example for ARRA projects that we're negotiating LGIAs last year, this also relates to uncertainty. A project which initially comes in with an interconnection request and says, "I'm going to build, say, 1,000 megawatts," just picking a number, but it turns out that that 1,000 megawatt project, unlike a huge conventional gas combined cycle facility, in the world of solar development could be broken down into different segments or stages, phases, 250 megawatts, and we build that and get a PPA for that, and then maybe the next 250 comes a little bit later, and after that – well, the way the process was written, the way the rules of the LGIA were written, a project has to complete the 1,000 megawatts that it signed up for in order to be deemed legally in fulfillment of its Interconnection Agreement, so we found that this was a challenge for certain interconnection customers last year and we created a device called "partial termination," which essentially allows the generation developer to identify a staged or phased project upfront in the structure of the LGIA, with provisions that say, if the generator ultimately doesn’t build the last phase, or the last two phases, but it does complete part of it, then it does not default on its LGIA, there’s actually a predetermined cost that it pays to get out of the later part of its LGIA. We worked that out in the last couple of months of last year, it went into non-conforming LGIAs that we filed with FERC and FERC approved those. We’re now in our interconnection reform process we’ve currently got going on, we’re looking to make that a permanent feature of Interconnection Agreement pro forma, so that any interconnection customer that wants to use it could adopt it.

Finally, let me touch a little bit on the deliverability issue and resource adequacy. First of all, I just – and this may be obvious to many folks, but I think it’s worth stating, that the word “deliverability” has too many meanings and they’re used interchangeably, so just to be clear, there is what we adopted as a little convention was, well, “Deliverability” with a capital “D” is this thing that is related to resource adequacy eligibility. And it’s a test that’s performed on the peak load hours of the year, and there’s a very important fundamental reliability concept that has to do with resource adequacy, which is that, when you hit those peak load conditions, you can get 100 percent of your RA capacity – if you need it – allowing potentially for outages of some of that capacity, but you can get it all and it can all come into the system to meet your peak load conditions. If you compromise that technical requirement of resource adequacy, then you're increasing the risk that, in some situations, you're not going to have enough supply that can get in to serve peak load. So, that's Deliverability with a capital "D" and it's based on studies assessed during the peak load hours of the year. Then, there's what we've called "deliverability" with a smaller "d," a lower case "d" and that has to do with meeting the RPS requirement, which is, over a calendar year, 33 percent or whatever target that might ultimately become, of the energy that's consumed is from renewable resources. And in order to study that, we're looking at production simulations over 87, 60 hours of the year, and counting up how many megawatt hours are coming from the renewable resources, and does it add up over the course of the year to 33 percent. Now, in some hours, it's going to be a lot less, in some it's going to be a lot more, but it's a different standard of deliverability and one of equal concern, but it's just a totally different concept and it’s measured and verified in a different way. So when we’re looking at transmission planning for upgrades to meet the policy criterion, we’re looking at upgrades that are going to enable us to get 33 percent renewable energy on an annual basis. Finally, there’s a third concept which is not usually called “deliverability,” but in a way it’s a variation on the same theme because it has to do with the operating challenges of variable energy resources, and what everyone is aware of is that they are hard to predict, that they are volatile, and they can deviate by large amounts in very small periods of time, and they represent new operating challenges. So, when we think about being able to accommodate larger quantities of renewable energy, we also have to think about this third concept, the operational one, and how are we going to deal with that? Now, that also comes into play when we’re dealing with import and export capability, as well, because you know, as you know, the Western Grid is really one big machine that is divided up into 38 or so different balancing authority areas; each one of them has to maintain balance within its own footprint. And yet, when there’s high volumes of renewable resources, that becomes more of a challenge. So, in smaller areas that are having, say, a high quantity of renewable resources interconnected to their systems, and yet need to maintain balance in their systems, the way they have to do that is to be able to export the variability, essentially have the neighboring balancing authority area, in this case the ISO who will be the recipient of a lot of it, be able to manage not only the variability of its internally connected renewable resources, but also to manage the variability that's coming across the interties. And so, we've developed and we're taking to our Board tomorrow, in fact, the Proposal on Dynamic Transfers, which will expand something we call "Dynamic Transfers to Renewable Resources," to enable them essentially to change the interchange between the ISO and the adjacent balancing authority area on an instantaneous basis to reflect the deviations. So that's a good thing in the sense that more resources from outside the ISO can come in and provide renewable energy, but it's also a greater challenge because now we're balancing for a larger proportion of the load.

Finally, on the RA expansion that was brought up with relation to IID, but also the methodology that we use for determining import capability, we have an initiative in progress right now, and while it's true – well, just let me tell you a couple of timeline milestones because I think that will help clear up where we’re going with this – we’re working on the generation portfolios and finalizing those now in collaboration with the Public Utilities Commission, to get a baseline scenario that will say, “How many megawatts of renewable generation in each of these areas connected by an intertie are in this baseline portfolio?” And so we get a number for, say, the IID balancing authority area, which is – I don’t know exactly, but let me say it’s around 1,500 megawatts; now, we will have that target number by the summer, and that number reflects a target based on the baseline generation scenario, but also a commitment in what we’re building into our transmission planning studies as to what we’re going to accommodate. In other words, putting the number out there doesn’t make it available right away, but it does say that this is the number we’re building into our transmission planning criteria, and we’re going to, if necessary, identify upgrades to accomplish RA deliverability for this 1,500 megawatts. Now, in order to determine when those 1,500 megawatts actually become available, we have to do the deliverability studies on the Grid, and that takes place over the fall and up through the end of the calendar year. And that goes back to the primary objective of RA, that we need to demonstrate that it’s all actually going to be deliverable to the system if we need it to meet peak load, and that's the deliverability studies; then, around the end of the year, as we're formulating our Comprehensive Transmission Plan, that comes out in a draft at the end of January, it gets finalized at the end of March, that plan will identify are there transmission upgrades that are needed for this 1,500 megawatts of targeted import deliverability, if so, what are those upgrades? And what's the timetable on which those upgrades will be ready so that we can look out year by year and say, "What's the progress towards that 1,500 megawatts that we expect to see year by year over the 10-year horizon, based on now the plan of implementing these transmission upgrades, assuming the upgrades are approved, etc.?"

So the timetable takes until March, end of March in the Final Comprehensive Plan, to lay out a committed timetable to these upgrades that will be built to get those 1,500 megawatts. But the actual selection of 1,500 as the target, and the commitment and planning process to build to preserve that target, will happen this summer. And I think I'll stop there. Thanks.

CHAIRMAN WEISENMILLER: Okay, thanks. I think it's probably useful for everyone in context to understand most of these projects that we're looking at under ARRA are project financed, and project financed contracts – I did a lot of due diligence before V. John got me into this current role, you know, people look at the contracts and the strengths of the contracts, and how they fit together. And so, one of the key things to the banks first is regulatory certainty, you know, there is always the statement at times that, you know, at least in China, as opposed to California, they let you build the projects before they abrogate the contracts. Well, here, it seems a fairly risky venture and that certainly affects cost and, again, the sort of commitments the banks will make. And the banks tend to look at the key provisions of the contracts, so one of the first contracts signed is the PPA, and the PPA specifies a price, specifies a date, has liquidated damages if you don’t meet that, and specifies a delivery point. And then people go off and get permits and stuff. Now, it seems like partially at FERC, or whatever, where these two different silos, one generation and one transmission, so after everyone has gone through, gotten their permits, based upon a PPA that, again, specifies price, date of delivery, and place of delivery, then we start looking at the transmission system. And at that point, we may say, “Oh, by the way, there’s lots of transmission capacity elsewhere, could you move the project?” Well, the PPA is structured, you can't move the project. You know, you're stuck there. And also, there's a delivery date, and so if you got to PPA saying you were going to deliver the power at 2014, and suddenly the transmission study comes out and says, really, it's 2017, then you're left to how does that work? How do you, you know, you're in breach of your PPA at that stage, or you're going to be at a breach and facing liquidated damages, and depending on the force majeure clause, and most of these don't have Reg outs in California in the PPAs, you could be in a situation at that stage where you're effectively in a breach because of the transmission system, which you didn't know at the time of the PPAs. And certainly, when you talk to the developers, you know, if they knew they were submitting a contract to deliver power in 2017, as opposed to 2014, there would certainly be a different price. So, in some way, we have to harmonize better the generation transmission pieces, otherwise, again, unless we can sync these up, the general perspective in the financial community is going to be that California is just not a place to do business. And I think, again, that's not acceptable for State Government. I mean, we have to harmonize these things in a way that facilitates the development. So, again, I think in terms of that gets back to Michael's question, how do we speed these things up? And how do we get the generation transmission planning much more in sync? So you're saying next year we'll really know a lot of this stuff. Well, we need people – people had to close financing to meet the ARRA deadlines, I mean, we might have a different world post-ARRA, but at this point, we really have to provide some regulatory certainty for the projects that were permitted.

MR. KRISTOV: Well, my reference to next March Transmission Plan was really in relation to the RA deliverability problem at the imports, which I think affects some developers, but does not affect the large majority of the development of resources like the ones in-State, they're not affected at all by that because, for them, deliverability is a different animal, it comes through the interconnection process, and I think the degree of certainty is greater there, provided that the transmission upgrades we identify in the in the interconnection process will move forward to permitting. Okay, so the issue, really, that I was talking about with this timeline was the import RA deliverability, and I understand that's a concern, but part of the portfolio notion is to identify a quantity of megawatts out there that are in the generation scenario. That does not necessarily mean that PPA's have to be signed already, that parties can still be signing those after we set the target.

CHAIRMAN WEISENMILLER: Some of that will be the case, but, again, I think I and the Governor’s office put a high priority on the Imperial County projects, you know, and those are indeed in the state and an area where we need the economic development.

MR. PICKER: I think that we all have good plans, but they don’t match up very well, and they’re effective to narrow purposes, but not to the larger challenge we face of buttoning up our shirts with all the buttons in the right places, and so that’s the central issue here. I’m not going to say at this point that we absolutely actually should in the future consider all the projects that come forward to the land use process, it may be that we make the policy decision, the transmission planning, actually determines which projects will get built and where. Currently, what I think is happening is that projects are driven through the process by where the good land use planners are. That’s a variable that is knowable, I know it, and I can pretty well handicap where areas are going to need transmission and where we’re going to have constraints because I spend a lot of time with the local land use planners. But I don’t see that that enters into any consideration here, so maybe we should simply make the determination that, since we’re all transmission planners in the room today, and you have the podium, that the decisions you made are going to govern where we have renewable resources, that may be no better or no worse than what we currently do. All I’m saying is that what we’ve got doesn’t match up, and you guys are out of line with what other people are doing, and they’re out of line with what you’re doing, and it won’t work.

MR. KRISTOV: Well, certainly at the ISO, you know, we’re not the resource planners for the State and I’ll go back to where I started, is that, to the extent policy makers narrow down the areas, the locations for development, then that simplifies the transmission decisions because we can focus on those areas where you’ve all determined are the optimal places to build generation.

MR. PICKER: Well, I’d like to think so, but that was part of the goal of the RETI process and it doesn’t seem to have resolved it.

MR. KRISTOV: Well, it seemed like there wasn’t enough certainty when you have 38 or so areas and scores, that still left too much leeway. Is there a way to narrow it down further to that, to a smaller number of areas?

MR. PICKER: Well, a certain official in a balancing authority simply suggested that everything that doesn’t fit the existing design plan for transmission should simply fail. And that’s a policy position, it’s not a – all I’m saying is that we haven’t really had the debate as to how we do this, and we’re not going to have that debate as long as people continue to move in their separate directions without really having an underlying discussion. Somehow or another, I don’t think we’re really getting there here, either.

CHAIRMAN WEISENMILLER: Anne, go ahead.

MS. MILLS: On that note of trying to get there, I guess, and my frustration, I’m Anne Mills from the California PUC. I want to start by apologizing because our permitting expert, Billy Blanchard, was originally asked to sit on the panel, which he also was drawn away by DRECP, so I will address some of what Billy wanted to address about permitting, specifically, and on the environmental review side, can address some questions on that, but I’m also going to touch on need, which is what I personally focus on more, so I’m better equipped to address those sorts of questions. And I’ve already noted a few from, Chair Weisenmiller, a few questions you had that I unfortunately can’t address today, but we can get back to you on.

So, just stepping back and looking at the progress we've made so far, between the Tehachapi project, the Valley to Colorado River, Sunrise Powerlink, and the El Dorado Ivanpah, the projects that we've permitted to date, we expect that those can deliver about 8,100 megawatts of renewable resources. If you add in the thousand megawatts that the ISO is now saying you could achieve with just wind and solar diversity in the Tehachapi, that gets us to 9,100 megawatts, so I just wanted to point out that number in relation to the Governor's plan that we would have 8,000 megawatts of large-scale renewables by 2020. You could say we're there on a transmission basis, but of course we are planning for more because there is a lot of commercial interest out there and projects moving forward.

The other projects underway right now at the PUC include the Eco Substation that San Diego talked about, Edison's Red Bluff Substation, and Edison's Colorado River Substation. We expect decisions on all three of those substations, which are primarily focused on interconnected renewables in mid to late 2011, and then we expect to see applications for more projects coming in in 2012 and 2013, including the West of Devers upgrade that Edison talked about, the Pisgah – Lugo line that would access renewables in the Pisgah CREZ, and also the Carrizo Midway upgrade where our staff has been working very closely with staff in San Luis Obispo County to make sure that the permitting they're doing on the generation side actually looks at the transmission fully so that we don't have to do any duplicative or additional environmental work when the permit to construct comes to the Commission. And then there may also be other projects as included in the ISO plan and to come out of the transmission planning process. So that's just a note on some progress.

In terms of challenges to date, on the environmental review side, obviously we've had delays and difficulty just getting permits from multiple state agencies and federal agencies, and I think the coordination with the federal agencies, in particular, has been a challenge in terms of timing, but we're trying to make progress there. With any sort of long linear project, there are significant cultural and biological concerns to address and lengthy requirements for surveys. We've seen difficulties in obtaining tribal land approvals, which of course is also holding up some of the West of Devers work. There are often visual concerns, residential and park areas, just controversy that drives a need for making sure that we have a really robust alternatives analysis that can withstand legal challenges. Of course, in the past, we’ve all seen significant conflicts with park and wilderness areas, and then all of this work requires time with environmental documentation for both NEPA and CEQA processes. Again, because we often see our decisions challenged and the only way they’re going to stand up is if we’ve fulfilled our entire requirements under CEQA and NEPA.

So that all is related to the environmental siting process in the permitting process. In parallel to that, the PUC has to look at the need for the line, and weigh that also against the cost. So, when it comes to need, I think this does – we really are trying to address this problem of, you know, uncertainty about the future, commercial interests maybe going one way, maybe land use would give you a different answer, maybe the existing transfer capacity on the transmission system would give you another answer. So we are trying to work very closely with the ISO and the CEC and other stakeholders to look at our reasonable pictures of the future and then work with the ISO to plan the transmission around those pictures. That’s why we signed the MOU with the ISO a year ago, and we’re making a lot of progress now, I think, on that coordination.

In the near term, I think the main issue that we see, or that we're anticipating upcoming with some of these transmission projects that will be coming into the PUC is the reliance primarily on the interconnection process, to identify them. Under the current ISO tariff, they really can't do any cost benefit assessment of those lines, and so the PUC in its past decisions has specifically said that we can't rely only on interconnection requests to find need pursuant to our statute, so we don't want to create more uncertainty and have a line that's approved in the ISO process, and then challenged and, you know, evaluated from scratch at the PUC. But we do have to find a project needed and, if that hasn't been assessed in the ISO process because of their restrictions under their tariff, that's going to create some uncertainty because we do need to find it needed.

This becomes even more of an issue when we know that we're only building these projects for resource adequacy, essentially for deliverability a few hours of the year, which kind of gets to, I think, some of the discussion we've already had. We need to make sure these lines are good investment for ratepayers and, honestly, a lot of these projects are coming in fairly expensive, and so the PUC has been very interested in opportunities for independent transmission and having lines identified out of the interconnection process is also an issue on that note because projects that are identified out of the LGIP don’t have the opportunity for independents to compete to build those lines.

I want to mention here that, just because of these concerns, we know the ISO shares some of these concerns about not being able to do a cost benefit assessment, and so we very much support the work they’re trying to do right now under what’s called the GIP2 process, their Generation Interconnection Process Reform, and we look forward to working with them on reform of this process that provide more certainty to everyone concerned.

I think that’s where I’ll stop, but I’m happy to answer questions.

CHAIRMAN WEISENMILLER: Thanks. I guess my questions were – I was involved in the PUC on Sunrise review and, as part of that, the Tehachapi going along, my recollection is there was not an economic assessment there, but it was based on the fact that those lines were facilitating renewables. Is that correct?

MS. MILLS: Yeah, and we don’t have to – there’s a specific portion of the Code that allows us to permit transmission for access to renewables, but we still need to find that the cost of that line is rational compared to the generation that it's accessing. So, in the case of Tehachapi, we found that the cost of the project relative to the 4,500 megawatts of RPS generation that it would access was reasonable.

CHAIRMAN WEISENMILLER: Right, but again, and at that point certainly there was a lot of discussion, particularly in Sunrise, on a rebuttable presumption issue that the PUC put out the decision saying, you know, one of the things we need to do is move away from repeated bites at the apple on these issues, and at least in that point, though, the context – the PUC had voted out the decision to give the rebuttable presumption to the CAISO on need, although I think it was on reliability projects and not on renewables at the time, and Sunrise actually wasn't implemented because of just timing issues, and I don't think it's been implemented since.

MS. MILLS: Yeah. The rebuttable presumption is actually given to the ISO's economic assessment of a line. And the decision that gave the rebuttable presumption also laid out very specific things that – specific standards that the ISO would have to meet in order for us to be able to defer, just because of our requirements around public process and due process and notification, and all of that. So, I think you're right that that actually hasn't been – we haven't been able to rely on that rebuttable presumption to date. But, again, in the case of projects coming out of the Interconnection process, there isn't any economic assessment of those lines, so it wouldn't apply in any case.

CHAIRMAN WEISENMILLER: Right, but again, they are facility renewables, so you get back to the other leg and certainly the leg that's been more traditionally used, again, in that context I think for Tehachapi, the ISO was struggling to come up with an economic assessment and eventually just pointed to the renewable use, and that was the basis for the PUC decision.

MS. MILLS: Right, it was, but again, weighed against the cost of the project. And that's what we're starting to get concerned about some of the projects coming out of the ISO process is the cost of those projects relative to the generation that they're accessing.

CHAIRMAN WEISENMILLER: And so that gets back again to the LTTP stuff which basically resulted in the original contracts for the projects. Again, it's sort of how do we have within the PUC one shot at cost, just given the timing and issues there, how do you have a coherent generation and transmission determination on stuff?

MS. MILLS: Right. Well, the LTTP process didn’t result in the RPS contracts we have now, and several of the projects even that are coming out of – that have signed LGIA’s and are resulting in lines coming out of the LGIP process don’t even have PPAs, some of these are still trying to negotiate PPAs. What we’ve done in the LTTP process, and this coming ISO planning cycle will be the first time we actually implement this, is we’ve now tried to take a look at what we think our reasonable visions of the future, including SUs around, you know, what projects have PPAs, but also where do we think projects are most likely to get permits, and all of that, and now the ISO is going to consider those. We’re working on the one base case that the ISO would use and our intent is that projects that are consistent with those scenarios would have a very smooth need determination process at the PUC because we’ve already in the LTTP weighed those alternatives and weighed the costs and the values of these projects, and these are alternatives we thought were reasonable.

CHAIRMAN WEISENMILLER: Okay. Thanks.

MS. KOROSEC: All right, then, I’d like to thank our panelists and we are ready to move on to our next presenter, who is Grace Anderson.

MS. ANDERSON: My name is Grace Anderson and I'm with the California Energy Commission. And I wanted to thank – it's good to see you and thank you for keeping your eye on the Western Interconnection horizon, and leaving room on your agenda for us to go over four western region trends that, if they continue to evolve in a successful direction, can support California's efforts to meet its renewable energy goals.

The four trends I've identified are related to the priority for renewable integration, the progress on real transmission projects, the central focus of the Western Planning, which is for renewables, and then, finally, a sustained interest in multi-state expansion projects. I'm going to go through all four of these very quickly and then pause and talk about, well, what might these mean for California policy. Each one, I could spend a whole day on, and many people have spent many days on them, but if you bear with me, I'm going to move very quickly, at a very high level.

One of the most interesting, fairly recent developments is that the WECC, the regional entity for the Western Interconnection, is exploring the benefits and costs of establishing an energy imbalance market.

This would be a real time centralized energy dispatch, it would be voluntary, it would be security constrained, it would look at energy and balancing needs, resource and transmission characteristics, energy offers, and it would create the optimal five-minute dispatch. This is a very high interest to the Western states. Through their State Provincial Steering Committee, they have contributed money to the benefit cost assessment of this possible market, they hope to host a major gathering of the CEOs and regulators later this summer to identify whether there is support for moving ahead with this voluntary market. They are urging WECC to make a go/no-go decision, whatever it is, by the end of this year. Obviously, the goal in terms of renewables is to distribute variability across a larger footprint. There are major unresolved issues and I certainly don’t want to predict this is actually going to happen, but I wouldn’t under-estimate the West, I’ve seen it accomplish a lot in the last 10-12 years, so more will be revealed on this.

So, my second topic under renewable integration is something called the Joint Initiatives. This, again, is a voluntary set of players who identify important initiatives and work together to see if they can find solutions. There are three that have been under development for several years, and they really are reaching fruition in 2011. I'm not going to go into the details on each of these, except to say that inter-hour scheduling is really focused on standardization of business practices. Ten Western utilities are already implementing 30-minute schedules and 15 more, including several in California, are moving toward, all things being equal, working for this scheduling at least for a first phase of unexpected requests by July of this year. Dynamic scheduling system of the DSS system is already implemented, and that is focused on communication so that we can move from 1:1 bilateral transactions to more of a clearinghouse where multiple transactions between multiple BAs can occur simultaneously.

Finally, ITAP, I'm not going to speak about this, but it's in the product development and software phase, it's going to be designed to have web-based visibility of inter-hour bilateral energy and capacity transactions. So, again, more will be revealed on all three of those fronts.

So, the third topic related to integration is very quickly on dynamic scheduling. Lorenzo mentioned this, and I'll just say that the West really has brought together the best of the technical people from all the utilities to try to better understand not only our dynamic transfer capabilities, but the potential limits on those dynamic transfers and they've completed their first phase of work and they've concluded that increases in dynamic transfer capability requires system enhancements and, of course, the ISO and the BPA have done very detailed studies on this and reach somewhat different conclusions. Lorenzo mentioned that the ISO is making some changes and this group has identified some options that would increase the ability of the system to respond automatically, which is particularly important for BPA. I'm not going to go into these, but the whole goal is to export that variability to the load areas that can absorb it better.

So my next trend is related to the real transmission projects in the broader West and you've heard today that there is a lot of work underway and we are building and investing in California, and the same is true outside of the state. One way we organize this kind of thinking is from the Sub-regional Planning Group, SPG perspective, we have a vibrant SPG function in the Western Interconnection. For the first time this past year, the sub-regions organize themselves so that they can have a coordination group, and that group integrated eight SPG plans, those that were completed in 2009 into two maps that merged them altogether, and you can’t see this writing very well, but they are all on one map, which is a breakthrough. And I just will say that this coordination group went through a quite detailed process and reached consensus on what it considered the 30 foundational projects which would have a very high probability of being online by 2020. And these are the larger, over 345 kv projects, so there are more than this in the West, but this is the main line group, and one thing that is important about these is that they are included in the base case, the reference case, for the region-wide planning effort I’m going to talk about in a moment. What’s important about this also is that these projects are mainly within individual sub-regions, they’re really designed to provide load service reliably, and they do access some renewables and conventional resources. These are not the group of lines that would be very long and multi-state and large, those are in a group called potential projects, which I am not showing the map of. So, CTPG, I want to say, and the ISO have been active in the sub-region coordination group, and going forward as this list is updated, it will be more reflective of the 2010 work of both of those SPG’s.

My third trend, if I remembered to change these slides, is that we have a greatly enhanced effort underway related to transmission planning in the Western Interconnection, actually developing the first ever 10-year plan, and I want to state that this planning is focused on delivering renewables. And this work is supported by over $26 million from the ARRA funding from DOE. It's important because the TEPC which – thank you for introducing that acronym, I wasn't going to be brave enough to do it, has a reference case which is compliant with statutory RPS west-wide, so we're not doing a fossil case vs. a renewable case, we're doing a reference case that's statutorily compliant and then we are looking at different ways one might achieve that, how transmission congestion might change with a high DSM case, with a low carbon case, or with changes in the operation of the existing coal fleet. The Western states are engaged through a steering committee and I thank Michael Picker for going with me to some of these meetings, and I believe Commissioner Peterman may be joining us in the future. What's unusual and, for the first time also, is that all the load forecasts and all the renewable requirements have been vetted through the states, they specifically developed these cases and they also have requested specific changes, changed cases such as are listed here. CTPG, its members, and ISO staff are engaged at quite a level of detail and I would just also say here that, looking forward, we really are going to have greater integration with the CTPG and I would add my compliments to the remarkable progress that they made in really just one year. It's going to help bring the California assumptions and perspectives into the regional process.

So, with that, I will say that late yesterday they posted actually a copy of a 50-page summary of this plan, I haven't looked at it, I'm a little anxious because I expect it's going to have some results in it that might be different than California's vision, but we're working with them on that. So, if I look at this next slide, it just demonstrates the important point that we are planning for renewables in the West, the lion's share of incremental resources that were added are renewable, most of them in California, I will say. The only fossil that was added was what was already under construction and reported to WECC, and then what was necessary to address the OTC policies in California, as was recommended directly by the utility representatives involved.

My next trend, my last trend, is that we definitely see continued high levels of interest in long lines delivering remote resources to California loads. It's the high quality wind resources, in particular, that drive this market interest, and I want to emphasize that the utility and independent developers rely on FERC Order 890 and it’s framework, which requires that the region review the congestion implications of really any set of generation and transmission that someone is interested in examining. We don’t just make these cases up, they’re filed through an orderly process that’s complaint with Order 890. The WECC expansion cases that were requested under Order 890 do show benefits, these benefits can be large, some of this, a lot of it extends from the wind profile diversity, and significantly lower costs than the resources that are being developed closer to load. I put a question mark next to lower cost because Anne and I are working diligently with the WECC staff to better understand why their results show so much more benefit than California’s, we know it has to do with their assumptions about capacity factors, their assumptions about the cost of incremental transmission, the methodology which compares the very best of the remote resources with the least economic of the California resources, but we really don’t have a comprehensive understanding yet of why the results are so different, so a lot of the things that we try to address in the regional picture are related to the uncertainty of the path of development, that’s what’s been talked about here today.

So, just this next slide helps you see that there are many projects, there are different kinds of projects, and of course, procurement is the essential piece of the puzzle and we haven’t worked through that related to specific projects, and Mr. Picker has talked about the dynamic Western Grid and, of course, some of these projects might lend themselves to that approach more than others, and we have a voice in speaking to that. And Candidate in Northern California is an example of a project that’s on this list that is looked at from a regional perspective. So, with that, I’ll just maybe leave this on for a minute and say that, well, these are the Western trends and initiatives, I’m certainly not suggesting that all solutions are in hand by any means, but if these are realized successfully, then it really can help California achieve its own policy goals. For example, the EIM could allow five-minute schedules, which would reduce transmission congestion, it could increase integration at a lower cost. The joint initiatives could standardize and create tools for 30-minute scheduling. We’re learning how to understand what dynamic transfer improvements are needed and implementation could lead to increased intermittent integration at lower costs. The additions of the sub-region transmission projects strengthen the Western Grid and increase our ability to interconnect to renewables that serve other states or California. The plan can illuminate paths to a lower carbon future and identify potential benefits from a regional perspective. Obviously, this can create tension, but the challenge to us is to keep an open mind to look at the potential optionality benefits of lines and corridors that come into the state and could potentially backstop some of our own solar and transmission lines. Finally, the high quality of remote resources put competitive pressure on California’s procurement, which could equal a lower cost in-state procurement result with more renewables being developed and interconnected under the cost cap under the new legislation.

So, I’m going to end here. If any of these initiatives have caught your attention, we’d be happy to provide written details for the body of your document. And I’ll just end by reminding ourselves that plans are useless, but planning is indispensable and we’re doing a lot of it. Thank you.

CHAIRMAN WEISENMILLER: Thanks, Grace. I think the question I have is sort of building off of Michael’s, is that it seems like a lot of – flip back to your slide 11 –

MS. ANDERSON: There we go.

CHAIRMAN WEISENMILLER: There we go. It seems like a lot of these are essentially trying to work off of the feature of that if a project interconnects with the California balancing authority, it's considered a sort of higher tier for RPS purposes, so it seems like we're seeing a lot of what I assume are DC gen-ties getting to the California balancing authority from these remote locations. And that gets to, I think, Michael's point about trying to essentially have something that's much more of a West Coast vision, shall we say, the power flows back and forth, as opposed to everything hitting California.

MS. ANDERSON: Well, you're certainly right about that and the results that will appear in the WECC 10-year plan shows that the DC kind of gen-ties really have the most economic attractiveness from a regional perspective, they show the highest cost savings. So, if this West Coast division is going to be articulated in the context of the Western planning, you know, we need to speak up about it. You know, I don't mean to be a devil's advocate, but we really have to look at the market and see what renewables in California are going to be competitive and in which of the western load centers to have a complete puzzle picture of what it is we’re going to develop and who we’re going to sell it to, and then what lines would make sense. And, you know, I really want to say that the WECC staff is trying to think outside the box, and they are hearing – Michael has made two really very good presentations in the State and Western Region forums, and if we’re serious about this export path and we could be thinking about the DC lines that go both directions, and take the California solar and geothermal resources to the SPP through the interconnections between the two, the west and the south, maybe we can get some of our solar power north, we certainly have a long history of moving our power to the northwest, and vice versa, so Canada and Northern California is another candidate. This is a concept, but I haven’t been able to sell it yet very well out in the west.

CHAIRMAN WEISENMILLER: It seems like the long gen-ties, the problem is going to be what are the benefits for the states between here and there in terms of on the permitting process. The one thing that is sort of surprising is, given the BPA situation, or just dealing with the wind capacity integration issues overwhelming their system, and I guess at this point you’re looking at shutting down the wind given the hydro, that aside from the COI upgrade, there isn’t more attempts to increase the capacity between here and there.

MS. ANDERSON: Well, when I originally wrote this presentation, it was all about planning and the plan, and I narrowed that down and took a lot of information out, but the results of the 10-year planning studies have indicated that the major areas of congestion in statutory RPS future are moving power out of Montana and then moving power from north to south into California on the COI and the PGCI, so those are the two areas of concern that will be highlighted in terms of congestion in the 10-year plan. We do see very significant interest in the British Columbia, Canada to Northern California line and that’s one of the important opportunities that is being examined in the planning process. We see some low-hanging fruit, that’s what they call it, in upgrading some of the lines, you know, out of Montana and into the northwest, that however isn’t going to help with the problem that you’ve identified which is that would simply result in more wind coming from Montana and getting congested in the BPA system. So, we don’t have real clear solutions, but at least as it’s been described to me, Canada and Northern California has quite strong support from BPA and it’s a Brownfield project and they view it as a way to get some of the wind off of their system and down to California, so that the development can continue there, but yet they don’t have to absorb all the variability. We are in an over-generation system in the northwest right now and it’s almost a crisis, I mean, it is a crisis up there and so exactly how we’re – these are all very good examples of the challenges that a 33 percent future and higher, you know, can bring in the real operation of the system, and integration of the renewables. So I just want to emphasize, there’s a heartfelt intrinsic commitment to understanding and bringing renewables on the system west-wide, so that the work that WECC is doing is very important.

MR. PICKER: I think you both have captured a lot of the discussions that we’ve had with people about the Western Grid and WECC’s planning. I’ll just say that we’re writing a letter to WECC from the Governor’s Office kind of outlining the Governor’s Office perspective on this that should be delivered fairly soon.

MS. ANDERSON: And thank you for that, and thank you for coming to Seattle and delivering the details of the commitments to transmission and renewables in California. I don’t believe that the West really understood that. I’m thinking that, to the extent the

Governor’s letter can move toward looking at some of what’s in the plan, and some of what’s in the – you know, this is a biennial process, somewhat similar to the ISO’s, and the study program for 2011-2012 reflects requests from developers for much higher levels of remote renewables than we’ve looked at for this 10-year plan, and they are going to be increasingly inconsistent with what we’re doing here and it’s important to communicate that. Thank you for your time.

CHAIRMAN WEISENMILLER: Thanks. And now to public comment.

MS. KOROSEC: All right. We did ask for public comment to be limited to those with time constraints and I have three people that were identified with that. Our first will be Rich Lauckhart from Black and Veatch. Rich, if you want to come up to the center podium?

MR. LAUCKHART: Yes, I’m here to give Black and Veatch’s view of renewables, where they will be built in the West. We’re particularly qualified to give a view because we are extremely engaged in all aspects of that business in North America and particularly in the West.

We have a 25-year view that we put out, a baseline view of where power markets are going, it’s not a stakeholder-driven view, it’s a view that we prepare and market, and use it in due diligence analysis and various economic analysis. It’s a baseline view. We certainly understand we don’t have clairvoyance about the next 25 years. But if we look at the view and look at where renewables are going to be built in that view, renewables in our baseline view are located in the states pretty much where the RPS requirements are, and that means that most of the renewables that we have, in our view, that are being used to meet California RPS are located in California. And these are the reasons that we came up with that view: one, renewables in other states can be somewhat lower costs than renewables in California, busbar cost and the $70.00 through $100.00 megawatt hour range, but that’s not dramatically cheaper than you can build them in California, and then, on top of that, of course, you have to add the transmission cost and losses incurred to get the power to California; second of all, a lot of that out-of-state resource is wind; the wind pretty much generates more at night than during the day. It’s not as useful when it’s generating at night; third, the cost of transmission associated losses needed to move these, if you have to build new transmission, is significant; fourth, more importantly than the cost of this long transmission lines to bring them in is the concern about the ability to permit them and that’s what you were just saying, is what are the intervening states' benefits here. Can they be permitted? Can somebody count on those transmission lines to be available? So, fifth, utility resource planners in California, these resource planners of these utilities that are here today, they recognize all these issues. These are not surprises to them. They understand that, and for that reason they are mostly contracting for renewables inside of California.

There are some exceptions to that, but mostly they are contracting inside of California. California has significant solar resources and we've heard there is 70,000 megawatts in the queue, not all solar, of course, but a lot of it is solar. And while the busbar cost of solar is higher than $100.00 a megawatt hour, maybe on the order of $140.00 a megawatt hour, the sun produces its energy during the daytime when we need it, not at night when we have our lighter loads. Recent declines in the cost of solar have made it very difficult for these out-of-state resources to compete with in-State California resources. BC-based renewables are particularly challenged because they don't have tax credits that they get for renewables that are being sold to the United States, they don't get those tax credits, that's a major competitive disadvantage for their resources. California legislation has greatly restricted the use of renewable energy credits, you know, the stuff has to now either be – it has to be either located, connected to the CAISO Grid, or dynamically transferred between firm transmission plus something on the balancing authority regime.

Now, some California utilities – and Mo is one – have found ways to bring resources in over pretty much existing transmission lines, they've said, "I have some capacity there, it's available, or I can increase that capacity somewhat, and I can bring some renewables in," they're doing that. But that isn't really the issue with most of these out-of-state guys that are trying to bring stuff to California. So, it's going to be a challenge, it's a big challenge for these out-of-state people to compete to sell in California and, for that reason, our baseline view is not much of it is going to happen. Now, having said that, I need to make sure – I think you guys already know this – that there are some very competent people working on renewable projects far away from California and new transmission lines to bring it here, in the hopes of helping us meet our renewable goals here cost-effectively, and giving them some business. And if they are able to bring those to us, if they can bring those good projects, and it's projects that we conclude that we want, then of course California needs to make sure that they have transmission inside the state to be able to accommodate that. But, you know, until that actually gets moving, it's a little premature to start planning for transmission in the state for these projects that are not quite at the status of being able to be sold to utilities here.

CHAIRMAN WEISENMILLER: Thanks, Rich, we are certainly looking forward to your written comments.

MS. KOROSEC: All right, next we have Steven Kelly from Independent Energy Producers.

MR. KELLY: Thank you, Commissioner. Steven Kelly with the Independent Energy Producers Association. And I want to spend a few minutes bringing a slightly different perspective to the issue of transmission, that's the perspective from the generation community, particularly the independents. I want to speak a little bit about kind of bringing a historical perspective, kind of IEP's goals, and then maybe make four specific recommendations when we think about this problem.

First, it's important to recognize that, from the generation perspective, the development of renewable resources is extremely competitive today, there are hundreds of companies, thousands of projects, tens of thousands of megawatts being developed and proposed and thought through. The reason transmission is important is because there is a limitation on the development of those projects. There's going to be a limited number of corridors and a limited number of investment opportunities to build transmission to access these resources. That makes the competition even more important and the way that the transmission is developed needs to take into consideration the competitive impacts of the transmission projects that are being proposed. We have spent 10, 15, almost 20 years, working to improve transmission access and making it non-discriminatory, and we've essentially succeeded in that. And that was resolved pretty much at the Federal level through FERC. We're now looking at something slightly different, it's the issue of corridors and where the transmission is going to be built, and to who is it going to access, and that is now becoming primarily a State issue, even though the Federal Government, FERC, has some authorities in this regard, this is going to probably remain a State matter. That means that it's important to the generation community to know in advance where these transmission lines are going to go, to know, for example, within a corridor whether it's going to go to the left-hand of a corridor, or the right side of a corridor, is it going to go to the middle of the corridor, or all the way to the end of the line? These things are critically important from a generation competition perspective. We're in a world where most of this is being developed and designed by the utilities, as was discussed this morning in that CTPG and the ISO are fairly well utility dominated in the development of these plans. Many of these utilities are actually involved in developing their own transmission projects and their generation projects. That creates a competitive issue that I just want to make sure that this Commission is focused on as we move forward.

IEP was involved in the RETI process, as you know, we sat on the Stakeholders Steering Committee, and felt that process was very instrumental in moving transmission planning forward with a lot of stakeholders at the table. And we regret the fact that it kind of – its demise. Since that time, most of the transmission planning has been undertaken by the CTPG as the primary input into the ISO statewide comprehensive plan. I just want to give a little bit of – it's my experience working with the CTPG –

CHAIRMAN WEISENMILLER: Steven, you have to speed it up.

MR. KELLY: Okay.

CHAIRMAN WEISENMILLER: Why don't you jump to the four points?

MR. KELLY: Well, the four points are, first, we would like to see better coordination and planning schedules, something Mr. Picker was mentioning this morning; rather than build off a metaphor of a shirt with buttons, we might want to consider a pullover sweater to have this coordinated planning happen at one time, so we don’t get the disconnect between the buttons and the shirt. Secondly, I’d like to see more availability of real-time access to the data that is used for the transmission planning studies, the base cases and also the scenarios. I don’t believe this is particularly confidential and it ought to be available to the public. Third, it’s important, I think, for all the state agencies to work on a set of common planning assumptions in this regard. It is difficult to plan projects when the planning goes through a CTPG process, an ISO process, and the CEC and the IEPR, and the PUC, and those, and different planning assumptions come to the table, so we’d like to see the agencies work to bring common planning assumptions to the table, and then fourth, and probably the most important, we’d like to see the planners work on a publicly available, what I call an Assumptions Workbook, which lays out the assumptions that are being used for the various planning studies and describes the changes in those planning assumptions as they occur over time, or as they move from one agency to another. I had requested that kind of information when RETI transferred over to CTPG and we were not able to get any kind of explicit information about what the changes in the assumptions were, but I think this information is particularly helpful for stakeholders who don't have the time and resources to spend the incredible amounts of time in the details of these planning things, so I think bringing up to the fore at least a workbook on the assumptions would be very helpful for stakeholders to follow this process. And those are my comments.

CHAIRMAN WEISENMILLER: Okay, thanks, Steven. We're looking forward to your written comments, too.

MS. KOROSEC: Next, we have Eugene Wilson from Sierra Club of California.

MR. WILSON: Good morning, my name is Gene Wilson, here on behalf of the Sierra Club, California Energy and Climate Committee. Thank you for the opportunity to address the workshop on renewable transmission. Our concern is to urge the Commission to consider more fully how the goal of 12,000 megawatts of distributed generation in the Governor's Clean Energy and Jobs Plan will affect transmission needs. In particular, new utility ratepayers need to pay billions of dollars for transmission that is proposed; how will that need for additional transmission be affected by the build-out of the 12,000 megawatts of distributed generation? Will the obstacles that the Commission has identified in terms of delays in the building of this transmission be resolved to some extent by the 12,000 megawatts of distributed generation? None of the presenters that we heard this morning, that I heard, addressed that topic at all. The transmission structure is apparently going to take up to a decade to build out, distributed generation can be built out much more quickly. The Public Utilities Commission has studied a high DG scenario in connection with the modeling of the 33 percent RPS standard. The high DG scenario modeled 15,000 megawatts of DG. In that modeling study, considerably less transmission was required than was required under the hybrid study. The comments here may not entirely reflect the transition to a higher DG scenario. So, we urge the Commission to consider carefully how the deployment of 12,000 megawatts of DG will affect the transmission needs and our ability to roll out renewable energy resources economically and quickly. Thank you.

CHAIRMAN WEISENMILLER: Thank you for your comments and for your participation in these workshops and the other IEPR workshops.

MS. KOROSEC: And our last comment is from Carl Zichella from NRDC.

MR. ZICHELLA: Good morning. I'll be on the panel next, so I don't want too much time, but I wanted to comment briefly on the west-wide issues that were raised by Grace and followed up on by the commenter from Black and Veatch. I've also been a stakeholder in the WECC-wide transmission planning processes, and a number of us who have been interested in renewable energy integration across the west have been particularly interested in maintaining and having California exercise its market power to encourage renewable energy development in some of the high resource areas elsewhere in the west. The reason is quite simple, our goal isn't 33 percent, that's not the goal, and California's efforts to get renewables into the system is to mitigate climate impacts on our state. We have enormous market power, we can waste that market power by closing our doors, keeping ourselves focused inward, or we can look at doing things that encourage a broader energy market across the west, that encourages our neighboring states to develop their renewables in a way that helps us phase out coal plants that we would not otherwise have much of a handle on getting rid of. The coal fleet in the west is quite old, we have some great opportunities with new Clean Air Standards to get rid of many of those facilities. If we're able to have bilateral relationships of the kind Michael was talking about, it would go both ways and we would be able to do some really creative things to retire more carbon out of the system, accomplish our client mitigation goals, and create jobs not only here, but elsewhere throughout the system, to create a momentum for renewable energy development across the West. I wanted to mention these things, we've had conversations with the staffs of Governor Sandoval in Nevada, Governor Burr in Arizona, and I had dinner last week with Governor Kitzhaber in Oregon. There's intense interest in cooperating with California on two-way exchanges of power, seasonal exchanges of power, that haven't been contemplated by the kinds of analyses we've heard so far this morning, especially not from the Black and Veatch perspective. There is a chance here to do something really big and I hope that we'll be able to take advantage of our market influence to make it happen.

CHAIRMAN WEISENMILLER: Thanks, Carl, looking forward to seeing you this afternoon. I was going to say, obviously, when Grace was talking, I was referred to West Coast Vision in the '80s, that was a major effort between this Commission and Bonneville and others to come up more with a regional approach to try to look at seasonal diversities, load diversities, resource diversities, and to try to figure out ways that overall we can work together; obviously, that fell apart in the energy crisis. But, anyway, it certainly is part of the things we're struggling with, but as you know we also certainly follow the California law. Thanks.

MS. KOROSEC: Chair Weisenmiller, we're running about 45 minutes behind, so I wanted to ask if you wanted us to maybe take a shorter lunch or go ahead and give folks a full hour?

CHAIRMAN WEISENMILLER: I think we should go for the shorter lunch.

MS. KOROSEC: All right, why don't we come back at 1:15?

CHAIRMAN WEISENMILLER: Exactly.

MS. KOROSEC: Great. Thank you, everybody.

(Recess at 12:34 p.m.)

(Reconvene at 1:17 p.m.)

MS. KOROSEC: Judy, did you want to say anything before we start the second panel?

MS. GRAU: I just want to make one correction to one of the slides I had this morning. I had 14 entities that had responded to our Transmission Data Request.

The actual number was 15, I left off IID; however, I did correctly note that they sent the forms and instructions because I had their projects on my graph, but I neglected to put them on the actual slide. Okay, so now we’re going to start our second panel discussion. I think we may be missing one or two, and I believe – is it Carl Zichella and V. John White would like to go first if that is not a problem for the other panelists, because they have time constraints.

For this panel, none of our panelists have Powerpoint presentations, we wanted this one to be a little more free flowing, and we’ve asked them to keep their opening remarks to five minutes. And so, with that, we will start with Carl, and then we’ll go to V. John White, and then just around the room. Okay, thank you.

MR. ZICHELLA: Good afternoon, Mr. Chairman. My name is Carl Zichella. I work for the Natural Resources Defense Council. It’s a pleasure to be part of this workshop today. The questions we were asked to think about were what changes we would make in the transmission planning, permitting, and construction processes to ensure appropriate and timely transmission upgrades for renewables, and secondly, how we might go about shortening the planning, permitting, and construction cycle to about three years, nothing like a light lift for us to think about.

I think we heard a lot of good conversation in this morning’s session, much of it is very applicable to this conversation. I think, clearly, we have a lot of planning going on in a lot of different places in the State of California, and it’s difficult to get to a decision point without participating in a number of different processes. I think Steve Kelly’s comment at the end of the morning session was very much on the mark. So, one of the things I think we could really do to help ourselves is to better coordinate planning across the various entities that are doing it, and have more of a real time collaboration on what’s going to be built, where, and when. I think, in order to help that process, we’ve learned a lot from the RETI process and other stakeholder driven processes such as the WECC transmission process, the planning process that Grace Anderson spoke about, but stakeholder participation would be a key and integral part of such an effort, along with, I think, a very high degree of transparency, so that people really understood what we were talking about in terms of what the assumptions were. Having a common set of assumptions that were based upon the best available information, obviously, would be a great aid to that process.

Secondly, I think that we need to utilize processes that institutionalize – or, rationalize, rather – transmission decisions. There are several processes, you alluded to one earlier yourself, the Desert Renewable Conservation Plan, that when completed should greatly enhance and accelerate transmission construction and project location throughout California, and actually it's a model that I've been encouraging others to look at throughout the rest of the Western United States because the idea of looking at generation and transmission together, and also looking at the conservation decisions that need to be made, are hugely beneficial in terms of timing, in terms of getting the generation and the transmission synchronized, in terms of when it will be ready, and also in terms of keeping the various stakeholder groups and constituencies that care about the natural resources engaged in helping to make the best locational decisions from a geospatial perspective that we can.

One of the key goals for the State of California, when we talk about climate mitigation has to do with what kind of future we're going to have for the species and habitats in our state. And decisions we make about infrastructure that are going to last a half century or more, it’s critical for us to also consider the conservation judgments that we have, so we can have climate adaptation that enables us to preserve these resources for future generations. We are really really blessed in this state to have some of the greatest diversity in the entire continent and species and habitat, so protecting those, I think, goes hand in hand. So, the DRECP is a critical tool. Along with that and related to it is the Solar Programmatic Environmental Impact Statement. We need to make sure that those two things, the DRECP and Programmatic Environmental Impact Statement that BLM adopts are synchronized in terms of its goals and the locational decisions that are made. Also, I think we need to look at some new ideas that are emerging that can help us do things better and more quickly, and one is the idea of doing master planning with end zones. This is an idea that’s emerged in the Central Valley by an innovative group of developers looking at using retired farmland in the West Lands Water District for large scale renewable energy development, doing it in a master planned way, inviting a number of generators to come in to an area that has already had environmental review done to it, being able to locate their sort of along the lines of an industrial park, and being able to make transmission decisions, then, for the longer term, can help us look at other grid stability and reliability issues such as how we get more out of the Helms pump storage unit, how we can better match the generation profiles from Tehachapi, how we might be able to wheel Arizona Solar Energy to Northern California markets and so on. So, master planning with end zones is an idea that has not been fully explored, it's an innovation and I think it's a very promising one.

Finally, I think we heard a bit today, this morning, and I was heartened by it because it's an idea that came out of RETI, which I was an original participant of, to coordinate the IOU and POU decision making about both procurement and transmission. Transmission planning has been looked at, it was something that began in RETI to look at it altogether, to have all of the public and private entities participate together, it was carried further by the California Transmission Planning Group, and I think we need to institutionalize these relationships and create opportunities for us to get more out of the Grid by having better balancing opportunities between and among IOUs and POUs. I know that's a little bit of a touchy thing between them, but I think, as you heard from Mo Beshir and others this morning, there's an increasing effort to both make the interconnections between them better and give better opportunities for balancing than we had previously enjoyed. Having better grid utilization and strategic upgrades to the Grid, to facilitate that, it seems to me is one of the fastest things we can do to get transmission to happen. It’s no accident that much of what we’re doing in California with regard to transmission is really taking advantage of the existing system, or upgrades that are related to what have been commonly called the “Garamendi Principles” in California since the ‘80s. They were guiding principles in RETI and I think they have stood us in good stead because we have not had a great deal of controversy, with the exception of the initial false start with the Sunrise Powerlink, with some of the transmission decisions that we’ve had. We’re building up Tehachapi segments, only one of those segments had any real controversy attached to it. We have the Western Rivers to Devers transmission line that has been approved with environmental support, I might add, for the first time I think that you’ve seen in the State of environmental groups formally supporting a transmission proposal. There’s much more that needs to be done and I would add to the list of things that need to be done looking at the Midway to Gregg transmission upgrade that opens up the Central Valley Resource areas that have so far been discounted somewhat because they weren’t an original RETI zone, they weren’t part of the original planning processes, or emphasized to the extent that they could have been by the CTPG or the ISO, and I think that there’s considerably more commercial interest in that part of the state than we have previously seen, and many, as I just alluded to, real grid benefits to putting transmission enhancements in that part of the state.

Moving along to the second question, about three years, I think many of the same ideas apply to how you might try to get within a three-year construction planning and timeline. I think we need to look at interim siting guidelines that get us to the point where we can start to use the results of the DRECP and the Solar Programmatic Environmental Impact Statement. I think we need to look at coordination of the agencies as we do in the first question, and also, I think if we’re going to go to a timeline that is that aggressive, we may need to think about some sort of functional state authority that oversees transmission in California, helps do that coordination, helps direct it, coordinate it, and issue decisions about transmission in a more timely way.

There’s a certain amount of what we need to do to build transmission that takes a certain amount of time, and I just don’t know if it’s possible to cut all the corners. I think that we have seen, once you get to a point where you have an approval, construction can actually proceed more rapidly than people think. We’re seeing timelines around three to five years, instead of five to seven years, or even 10 years in many cases, for lines to be built. Of course, it depends on the length and the routing of those lines, but we can certainly do a better job throughout. It may take more of a radical approach, though, I think if we’re looking to try and institutionalize the three-year timeline for transmission planning and construction in the State of California. I’ll stop there.

CHAIRMAN WEISENMILLER: Thanks, Carl. I guess the question I have for you is – we all talk about getting better stakeholder participation in these various processes, and to some extent that’s more or less your middle name, is stakeholder on the transmission area. Looking at the CAISO, actually, obviously we can talk about the Energy Commission, too, but the Energy Commission, CAISO, CTPG, and then the PUC’s LTTP stuff, how effective are the mechanisms there for stakeholder involvement? And what do we have to do to facilitate that?

MR. ZICHELLA: Well, I think they vary, but, again, I would come back to something Steve Kelly said, and it's very difficult for anybody to participate in all of them. You know, you're creating a situation where, for an average person to be a stakeholder in transmission planning and the follow through and all the various moving parts of all of this, at the end of the day, you're asking somebody to basically give up their life or their career in order to participate in everything. And it's very tough. One of the things that RETI gave us was everybody was at the table together. And that's what gave me the idea to have some sort of transmission authority to help facilitate that and make it easier. And there are also levels of accessibility that we see. I think the Energy Commission, and all credit to you, is a lot easier process, say, than going over to the ISO. The ISO is really an inside baseball kind of game. It's very tough unless you're really very experienced, you've been at this for a long time, to be able to participate in a very significant way over there. It's not that they're holding you out, it's just that the quality of the information, how it's put together, you know, I'm on all of their email mailing lists and a lot of it is very tough to figure out, you know, which of these things is truly important to engage with when you have limited time and resources. So, I think there's a lot of processes and I think, similarly, the PUC can be a little difficult for stakeholders to participate. And the connection between all these things is not always clear. And that's why I think having better coordination from the beginning and having stakeholders engage at that level is really where you'll get the biggest bang out of them, and they'll get the biggest opportunity to have quality input.

CHAIRMAN WEISENMILLER: And it sounds like one of your recommendations, too, is that the regulators, both here, the PUC, and the CAISO, really consider seriously the BLM PEIS and the environmental comments there. How do we get that into the various forms? I mean, obviously you could say submit it here as part of this record, but how do we get it into the other forms?

MR. ZICHELLA: It's a good question. I mean, I'm seeing this in other places, too, in the Western Electricity Coordinating Council, you know, they have sub-regional planning groups, as was mentioned by Grace Anderson. At one of their meetings for their State Coordinating Committee, I asked them what they were doing to incorporate the information from the Solar

PEIS, and the answer was almost, “What’s a solar PEIS?” You know, so I think, first of all, we have to get all the various pieces before people and integrate them into those processes, they need to be considered. We’re doing geospatial analysis to find the places that are most easy to put projects in both of those processes and I think DRECP is the one that really will have a greater utility which is why they need to be linked, the Programmatic Environmental Impact Statement, and the Desert Renewable Energy Conservation Plan because those potentially have huge value, the generators to the amount of transmission we build, where it goes, and the possibility of opening the most promising areas, including areas like the West Mojave, for example, which has not been on the radar screen quite as much as it should be, because of some of the land use issues there, among other things. You know, this is something that we can overlook. I think a lot of the planning that’s been done to date has been based upon the RETI analysis which is a good thing, that was really the first time we’d ever done it, but I think in RETI we also realized there were many shortcomings to the data that we had to use. So, the Desert Renewable Energy Conservation Plan fixes that problem. So, if we’re only looking at RETI data, we could make some wrong judgments there. So, I think we have to have an iterative process where best information gets integrated into the process.

CHAIRMAN WEISENMILLER: And I think part of the challenge we're facing, I think it was alluded to this morning, and maybe Anne will deal with it more later, is that obviously we went from the RETI screening criteria that you came up with, or you and Joanna, then in the PUC process the Aspen Consultants tweaked that some, and now that's going into the LTTP, coming out of that would be the scenarios for the policy driven analysis. And so that, as I understand, is the flow now. Exactly where DRECP or the solar PEIS fits into that process, which will then go next year and drive the CAISO's processes, again, I think it's important to try to do the linkages so that we have, a) things have to occur quickly, but there are the best information as we go through these very steps.

MR. ZICHELLA: I completely agree. I mean, that's what we need to do, we have to link them up and we have to use the best processes, methodologies, and information that we can. We started something in RETI and I don't think anyone in RETI expected that to be the end of the conversation, improvements were always expected. We're doing a similar process across the Western United States using a process very similar to the one we used in RETI to integrate geospatial environmental information and transmission planning across the whole interconnection, so the things that we started there have become a model to be used, but not just to be static, must be done that way, improved upon so that they're used in the most useful way going forward. And the DRECP has a lot of scientific information about habitat information that's going to help us get projects in the best possible places and get incidental take permits in weeks instead of months or years. This is the thing that helps a project get off the ground, gives you more assurance that your project can be built, gives you a better opportunity to raise money to build it, and more assurance that you'll have transmission for it. I mean, this is – we are under a real crunch here, 33 percent aside, meeting an 80 percent reduction in carbon across the Western United States, and in California by the middle of the century is a tall order. And the clock is running on us, so we have to be more efficient in how we go about this. And these linkages and the coordination between the various planning entities is absolutely essential. And we can't expect stakeholders to be dropped between four different processes that are all making a part of the same decision.

CHAIRMAN WEISENMILLER: V. John.

MR. WHITE: Thank you, Mr. Chairman, Michael, Paul. I’m John White with the Center for Energy Efficiency and Renewable Technologies, and I’m glad to – first of all, thank you for accommodating my schedule and also letting me go after Carl because I can start by saying everything that he has talked about are things that we agree with. I want to try to get a little more specific in response to the questions.

I want to go back to something Michael said earlier this morning about determining factor in being able to be successful with regard to permitting is going to be minimizing conflict and controversy with the land use decision, and yet the process that we have now is one that is driven by the BPA’s, driven by the queue position, driven almost exclusive of those same kinds of considerations, and so there’s a lag time between those processes and the environmental constraints that are going to probably be the principle determinant of the ability to go faster. I think the past year, the extraordinary cooperation that has gone on between and amongst State and Federal agencies, and between and among California agencies, is still a relatively new habit, and the old habits die hard. And I think that we have to – one suggestion that I have for the last comment that Carl made is you need to raise the stakes and raise the engagement levels of the agencies so that, at some point, I'd like to see a meeting where we have ISO Board members, PUC Commissioners, and CEC Commissioners, all on the same dais, all hearing about these problems, and at that level getting a higher level of commitment to engage with each other. I think that the problem Carl alluded to now of what we have as stakeholder input, basically informed, but not in substance, because it usually is not a driving factor in the process and usually comes late in the process. I think that one of the things that we have to do, though, even within the agencies, is to have this habit of mind of listening and talking to each other to be sustained and continue. We are actively engaged in the Desert Renewable Energy Conservation Plan, but find at the moment that it's primarily a conservation strategy document. It is not yet been informed significantly by the energy resource opportunities in the desert. We're working to improve that and are hopeful that that will occur, but at the same time, you have a near total lack of engagement by some of the other key agencies that should be in that process, including the PUC, as well as some local governments, and so the DRECP has to be more inclusive and informed of each other's process, but if we're going to try to overlay the results from the DRECP on the transmission planning process, after the transmission planning process is already pretty far along, that's not going to help us get to that goal. And Sunrise is more than just a sort of an – Sunrise still colors the debate in the desert and a lot of this narrative about we can do this all with DG comes from the failure of the sponsor of that project to take seriously the concerns and interests of those folks in the environmental community who told them, we among them, "Don't go through the park." $150 million and four years later, a huge amount of conflict occurred and they decided not to go through the park. Okay, that's not a failure of the regulatory process, that's a failure of leadership by the proponent. And we have to avoid those kinds of paralyzing mistakes.

I also think that, while it's gratifying to have all of the nice things said about the project, we had the privilege to direct over four years of the Renewable Transmission Initiative. The lessons are already being unlearned. The comment this morning that the CTPG is not making its assumptions available is not especially transparent, sending out an email to people and having an internet phone chat is a sufficient stakeholder involvement, that's not going to cut it because, in fact, you’re leaving out very important constituencies that need to be included, but the agencies are also not without blame because one of the things that led to the demise of RETI was the refusal of the agencies to be willing to work together on a sustained basis and abide by a rough consensus, they all said, “We’ve got our own process and our process will govern.” And so that’s where we’re back to.

Now, I think it’s good that the Munis and the IOUs are staying together because, as Carl said, this is a critical part of the link, it’s a critical part of not building too much transmission, and a critical part of making the balancing authority area work. And this requires, again, high level engagement, not just with staff. We have the fortunate coincidence where the new General Manager of the Los Angeles Department of Water and Power started his career at the California Energy Commission when Richard Maullin, the new ISO Board member was the Chair, okay, that’s a relationship that we should build on and foster dialogue so that we can get the ISO and DWP working together and having an agreement that will enable us to have much more flexibility on a system, much less consumption of fossil fuels, and much better coordination on transmission.

I will also say that our organization is attempting to recreate the spirit of RETI, we have plans to launch a collaborative that would include engagement with these various proceedings so that there’s a home for people to come, that aren’t participating as actively in the other proceedings, we’ve worked with the environmental groups, worked with some of the Munis, worked with some of the independent transmission developers, all of whom want and believe this is a good process that we’ve been through; but the first time we had a conference call, we got a note from CTPG that their lawyer had recommended that they not participate in these meetings – the CTPG members not participate in this new collaborative that we’re trying to get underway to try to recapture some of that collaborative spirit because of antitrust issues. Somehow we would be engaging in antitrust, that they would feel uncomfortable participating. Now, that’s a little bit like being called ugly by a frog, okay? And I just think it’s suggestive of the problem when the silos get too deeply embedded. We think that there’s opportunities for us to do better going forward, we think some of these critical infrastructure backbone lines have to be moved forward, the Midway-Gregg line isn’t just for the West lands project, the Midway and the Gregg line is important for SMUD to have an opportunity, particularly if it could be some kind of joint project with PG&E, because one of the weaknesses in California's Grid is that the projects in the south have trouble selling to the north. And as a result, there's been an informal preference on the part of both PG&E and SMUD to buy from out-of-state resources through which they have access to the north and to the east. So that's a line that somehow didn't get moved forward in part because we don't know why, exactly, but PG&E was more interested in the British Columbia line than they were interested in this one. So, that's a line that we've got to solve quickly, as part of whatever planning we're doing.

The other thing we have to recognize is that the Imperial Riverside East Corridor is already congested, we have severe resource adequacy problems with Imperial and the ISO, so we could have a perverse outcome down there where the baseload geothermal resources and high quality solar resources end up getting treated less favorably from a resource adequacy standpoint than intermittent wind resources in other parts of the ISO system – that's insane, okay? We can't do that.

So, I think in addition to all the hard work and the good will that has been agenda over this past couple years by the work that you and Michael and others have done, we've got to bring the new appointees into that family, keep it at a high level so Commissioners are talking together and helping lead their respective staffs, rather than getting captured by the staff, and have an opportunity to go faster because we're making smarter decisions. I think we've got to find a way to get the transmission interconnection planning process reconciled with the land use constraints that we're going to face if we're going to go faster, and I think making all of this more connected and accessible and transparent, we can get there because we actually have made much much more progress in the past two or three years than most people outside of California would have thought, I think that's so much of the out-of-state momentum that is still present because people just haven't been able to imagine that we would get ourselves together enough to build three major transmission lines and get a bunch of projects approved and get the interconnections done. But, to be successful in the next five years, as we've been in the last two, we're going to have to raise the level of our game and raise the level of cooperation to new heights, and we look forward to working with you and others going forward to try to make that happen.

CHAIRMAN WEISENMILLER: Great, thank you, John.

What would be the three top things from your perspective to get to the three years, the three highest priorities?

MR. WHITE: Greater connectivity between and among all of these agencies that we have with a piece of this authority, and not just on an occasional, but on a regular basis, so that there is able to basically not have a situation like we're going to have this week where the PUC sends a letter to the ISO saying, "Your Transmission Plan didn't have enough competitive input and so, therefore, you ought to consider delaying it," which will screw up, you know, interconnections. That kind of stuff, we need to avoid. So the first thing is greater connectivity and cooperation, second is greater understanding of the very real land use constraints that are going to affect projects that we have been assuming are going to drive this process, and third is to have greater linkages between the Federal agencies that we have, that have a piece of this, particularly BLM and U.S. Fish and Wildlife Service and, again, that gets back to the land use – that one agency, as we've learned throughout this process, can delay everybody else's successful work if they're not brought in, and somehow accommodated. And it's not so much a matter of changing or giving in as a matter of people need to understand what these constraints are and we need to not marginalize them. I think that we're doing better, but not nearly good enough.

CHAIRMAN WEISENMILLER: Okay, my last question is just your take on the question I asked Carl about what do we need to do to enhance the stakeholder processes at the various agencies.

MR. WHITE: Well, I think I would agree with what Carl said, but my further suggestion is to create a single forum where all the Commissioners and key staff are present, and so we can do from a stakeholder standpoint, we can do one set of comments, and one set of testimony, and touch everybody's base while we're there, and hopefully foster – I'm not a big fan of reorgs because I think they take too long and are too destructive, but you could do a virtual reorg where you had a council of people that had all the decision making power together and meeting periodically to allow public debate and discussion about some of the key issues before them, and then listen to it all together and maybe you engage in conversations together, as well as among staff.

CHAIRMAN WEISENMILLER: Thanks, John. Tony?

MR. BRAUN: Thank you, Mr. Chairman. Tony Braun on behalf of the California Municipal Utilities Association today. Thank you for including me in this panel, which I hope we will have a robust discussion after the prepared remarks, and I think I'm going to alter my approach a little bit because we've got a lot of things that have been discussed today and maybe it would perhaps be the most effective use of time to really build on that.

There are roughly 45, 46 publicly owned utilities in the state, they are extremely diverse, large and small, high renewable portfolios, and ones that are coming up to speed, but they have a lot of things in common, 1) they are all equally subject to the AB 32 and SB 2X requirements, and what might come after that, and they're all load serving entities. And that means they're very very sensitive to the cost of the initiatives, both on the generation and transmission side, and how those are going to affect the end use customers that are their primary charges.

Mr. Picker talked about land use, I think it was almost to the day we were sitting in a workshop two years ago in the last IEPR cycle, and the current – the then IEPR Committee Chair kept asking the same people around the dais, what's the biggest issue? What's the biggest issue? What's the biggest issue? And it was land use, land use, land use. And when we get into some of these questions, we'll note that we're talking a lot about issues that we've made a ton of progress on, but the primary issue that seemed to have come out of that IEPR cycle was that somehow the land use needed to be more in the upfront part of the consideration process, and I'm not sure how much progress we've made on that. But I cannot emphasize enough, also that came out of the last IEPR cycle, was frankly a lot of collaboration and cooperation amongst the ISO, and the POUs and the IOUs about the transmission that they were already planning, that was on their books, and how that could be better communicated to the policy makers and to stakeholders at large, and that was the genesis of the CTPG, and it had a lot more cumbersome names, it was the California Joint Transmission Planning Work – I can't remember what they were called – but what we now have is the CTPG and immediately there were concerns about lack of stakeholder involvement and secrecies and assumptions, and things like that, but in my couple decades of experience in working in the utility business, those concerns, I think, morphed from we can't see what you're doing, we don't know your assumptions, we don't know your data, you're giving us too much information, you've got too many meetings, so I don't know what the right answer to that question is, but it's just evidence that we've come a long way from everything was done in a little closed circle to, now, what I think the challenge is: do you have the expertise and the resources to be able to meaningfully participate in these processes? I think that is the primary challenge from a stakeholder point right now.

The question for number two is, you know, what can we do in the future going forward? And I think, as a segue, I think we have to understand, at least from my perspective, what we're doing right now. This isn't a market-driven approach to renewable planning and resource development, this is a centralized planning approach, it is two or three entities that are going to call balls and strikes as to what are their favorite projects, what are the favored generators that get contracts, and everything and where the favored routes, and everything that comes from that, this is an integrated resource plan for a broader than one utility footprint. And once I think you get over that and say, you know, that's what we're doing, that is necessitated by the complexities of the siting, by the complexities of the procurement process, by the complexities of the fact that we are socializing the high voltage grid, we are asking multiple parties to pay for the cost, multiple billions of dollars of transmission investment, that this is not something where these costs are integrated into the bid prices of the generators, or the generators themselves are bringing a billion dollars to build a particular line, that is not the model we've adopted in California. We're socialized in the transmission costs, we're trying to decide what the highest priority projects are to get done. And so, once you're over that hump and you say, "Okay, we're doing integrated resource planning, we're going to declare winners and losers, how do we best streamline and pick what's the biggest bang for the buck?" And I think we need to consider some hard choices. Maybe we should have tiers of projects. Since we're declaring winners and losers anyway, why not put the most emphasis on the projects we think can get done the fastest and the cheapest? Those, I think, would include utilizing existing rights of way, those may include areas and corridors and rights of way which are already permitted. They would, I think, utilize a procurement process through our POU boards and through the PUC, which tries to take into account all the costs of delivering that renewable resource to load, not just the energy costs, but the integration costs, the capacity issue. I think maybe if we have that comprehensive approach to it, we get past some of these RA issues because, clearly, we don't need resource adequacy capacity from the 70,000 megawatts that are in the ISO queue, so why would that be driving a large section of our procurement process?

We’re calling balls and strikes anyway, why not have tranches of priorities where we are really going to, you know, say “these look like the best ones to do now,” and working off the assumption that we can’t do them all at the same time, that there’s just not enough manpower to get that done, and this is going to leave certain projects, both transmission and generation on the side of the road, it probably will disfavor some POU projects, but I don’t know other ways to get past this roadblock because obviously we can’t even process the volume of projects that we have in the queue right now

POU and IOU collaboration – we’ve come a long way on CTPG, the renewable bill talks about joint development of projects, I’ve worked closely with Imperial Irrigation District and Edison and the ISO to identify the Path 42 upgrades, which were an excellent example of all the entities getting together to identify and move forward with a cost-effective upgrade. There is, I think, other ways to take advantage of the fact that the POUs often have pre-permitted rights of way, or they may be able to use their own CEQA lead agency authority to assist in getting priority projects done, and that most of the major lines that were sited in

California historically are jointly owned. So, isn't there a way to perhaps utilize that historical model in today's context to further the joint development to share costs, to utilize some of the legal authorities that are out there right now that may be able to streamline the permitting and siting process. So, I think three things I would add to try to streamline, one, not everything is going to move forward, so we need to pick winners and losers and we're doing that anyway, so I think we just need to understand that's what we're doing and move on; and two, perhaps it's time to really prioritize what we're targeting and really put teeth to the least cost type of selection from not only transmission, but a generation procurement point of view so we can have the best mix of generation and transmission that will serve the overall power needs for Californians, both the POU an IOU customers.

CHAIRMAN WEISENMILLER: Thanks. I think both of us probably were thinking in part of the workshop that I think was under Chair Pfannenstiel, trying to understand how to do joint – why weren't there more joint projects between the IOUs and POUs, and at least at that point, I think the POU response, it was partially the different models of the utility and the different visions of transmission between how the ISO would operate it and the POU, so have we made any progress towards potential joint projects?

MR. BRAUN: I think there’s been progress in that general issue that you just talked about and we could get into a myriad of details about how the transmission systems are utilized and things like that, but it’s my observation that people care much less about the sort of market theories behind one model vs. the other, and are much more interested in how can the two models coexist. And frankly, it’s not that hard. Whether it’s the COTP or the SWPL, the DC-tie, these lines have rights held by IOU participating transmission owners, and ownership or rights held by the POUs. And they are managed. And they can be managed going forward in the new project. And so I would anticipate that, actually, I’m hopeful that the ground is fertile for those kinds of discussions because it’s just my observation that a lot of those market theory type arguments are yesterday’s newspaper and they’re not interested in pursuing them any longer.

CHAIRMAN WEISENMILLER: That’s good. As you know, it’s difficult enough to build transmission lines in California, that having to somehow build a POU transmission line and an IOU transmission line, it’s going to be very very challenging, as opposed to a joint line that uses the corridors more effectively.

MR. BRAUN: I think that’s everyone’s working assumption.

CHAIRMAN WEISENMILLER: What is the Muni perspective on the independent transmission? Obviously WAPA, I think, was with its ARRA money trying to leverage a number of independent projects. Have they gone anywhere? Does that fit with your model?

MR. BRAUN: Again, this is a practical issue. Who is best suited to build a particular project? And, generally, to us it comes down to cost. There is nothing magical to us about an independent building a particular line. If the independent is cheaper, we would greatly encourage that cost base competition. If the IOU is cheaper, there is no advantage that we see to having the independent build the line. They are all going to the same place for rate recovery and that is through the ISO’s tariff, through FERC to get a regulated rate of return. Some of the frustrations we’ve had in the ISO process have been how will the competition manifest itself because, to us, it’s not a matter of just having – if there are multiple options, there is automatically going to be cost-based competition. There is no mechanism that we can see where that actually occurs. I know the ISO has worked on that through their new RTTP process, but that's all potential. The independent projects, the Path 15, the Trans Bay Cable, they're all subject to the same rate arguments at FERC that the POUs have had historically with the IOUs. So, we don't see a cost of money advantage, we don't see any cost of construction advantage, we don't see any more willingness to take a risk, so I think this is the proof is in the pudding here, we don't oppose independent transmission, but we want to see that it actually brings benefit, as well.

CHAIRMAN WEISENMILLER: Thanks. Neil.

MR. MILLAR: Thank you. I'll keep these comments fairly brief because I'll just point back to a few of the points that were made, either earlier today, or in the earlier panel today. In terms of the improvements, I agree with your earlier comments that there have been improvements made in coordination, which I think is the single biggest area for making the overall process more efficient and more effective, coordination between the different agencies and between the ISO and the different agencies, so that the work that we do, we simply haven't moved to constrain the bottleneck down to the next party in the process. I do think we have some good successes to point to there in the work with the CPUC on developing portfolios and using their portfolios as the basis for planning. Also, as Anne mentioned this morning, one concern with network projects coming out of the generation interconnection process was that the ISO tariff did create the opportunity for us to advance projects that the CPUC would have difficulty approving and we are working on means to address that because that’s not helpful for anyone if we’re simply moving a project through the process for someone else to have to re-test and perhaps reject at a later stage in the process.

Also, just building on that, the memo that was signed about a year ago, that we’ve been able to bring more effect to is, I think, another sign of where we’re looking for opportunities to improve that level of coordination and those, to me, are the more meaningful stages of what can we do differently to make the overall process more effective, reduce the amount of review and re-decision that sometimes is going on through this process. And, as I mentioned earlier in my own presentation, the more certainty that’s developed more quickly around where generation resources are developing enables us to focus the transmission planning efforts more succinctly and helps remove some of the uncertainty that then otherwise ripples through into the actual siting processes. It’s very difficult to get a transmission line built anywhere, even when you can prove it's needed; when you simply suspect it's needed, it's a much harder sell. So that kind of certainty, the public who are often – many of the processes focus on stakeholder groups as opposed to actual landowners themselves, the more certainty that's given at that stage simply helps downstream efforts to get the projects approved more quickly.

I've heard a few comments about the transparency and the need for planning assumptions to be more visible. I encourage anyone to actually take a look quickly at the ISO process right now because we are in the midst of finalizing our planning assumptions for our 2011-2012 cycle. Those planning assumptions are public. I think – I haven't been in California that long, but my experience has already been that the assumptions get a lot more attention once people actually see the decisions that fall out of the analysis, as opposed to when you're putting the assumptions up for comment at the beginning of the process. It always reminds me of a Jerry Seinfeld episode where an emergency is announced in the plane, he's taking a flight somewhere, and after they make the announcement, there's an emergency, he says, "Oh, they are going to replay the safety announcement, aren't they?" Because nobody listens until there's an emergency. And I feel sometimes our consultation on our planning assumptions falls into that category, they don't get a lot of scrutiny until people see what they are leading to. The good news for us, though, is that we do have another annual cycle for people to bring in their revised comments.

The other part, though, as part of that, I was participating here both to try to provide some examples of where we're looking, but also to hear and get some ideas on where there are problems cropping up downstream, that we can get going even in advance of getting direction, but where we can look at to try to make the overall process more effective because success, to us, is actually getting the right lines built at the right time, not just getting our approvals. If that ripples through and affects someone else, and delays the process later on, that doesn't look like success. I'll leave at that for now. Thank you.

CHAIRMAN WEISENMILLER: Thanks.

MR. BESHIR: In fact, I don't really have much to add, but I will maybe just outline some of the things I had similar to what Neil said and also what was said previously. Talking from the CTPG point of view, and since then, I guess, domain is really the planning, number one, of course, is really the coordination aspect, that seems to be the key factor because that really leads to whatever we want to do. CTPG by itself cannot really meet the obligations or the need of the planning, we do need to get information from all the different parties, including the balancing authorities, California Energy Commission, from the Net Short aspect point of view, so all of the parties really need to support each other, so coordination is a key focus for us, and the faster, the more effectively and efficiently we could do those coordination, I think, really serves us well, and also could shorten the process a great deal if we can really manage that, but the different pieces, and we don’t really live in California only, we also need to really coordinate with all the parties within the Western Electricity Coordinating Council, so TEPC does play a big role and having membership in TEPC is going to really serve, as well. So that is number one. And number two is the stakeholder process. I think, as we say, we are learning as we go, we have – initially, we have started, I guess, there were a lot of things to be said, but I think we have perfected that process, but I think we do also – it’s going to be always room for improvement, so we are going to look at you to give us comments through electronically or come to our meetings, either website – through the WebEx, or face to face. So that's really the process we think is going to help us perfect some of our processes and get the input and so we can do the job better and serve, I think, the communities, the public better, also, by getting that information. So that's number two, for me, is really the stakeholder. The third, similar to what Neil said, is the assumptions, the planning assumptions. And one thing we are doing right now is we are trying to bring that way ahead of the process. So, as we speak, for 2011, we haven't really started studies yet, we are working through the assumptions. So we are going to have a workbook available for everybody to see what are assumptions are for some of the key aspects before we even start cranking any Ks or any studies. So, we are taking meticulously through the process, put all the major assumption points which make a big difference in the studies, and we are encouraging people to see this before we actually do the study and later on, I guess, as Neil was saying, we really want to do that, we want to really bring that and get your comments early on in the process. Fourth, I guess, is the comprehensive planning, I mean, the planning – there are different layers of different things that we could do, resources becomes an issue, but I think some kind of smart planning concept, you really need to be involved so that, at the end of the day, we will have addressed some of the key issues and so that we will have comprehensively looked at from the Bas, the balancing authorities' point of view, the independent transmission folks, the different aspects of the performance of the power system, all that is really included, and inclusive in that planning process. And finally, I guess, is at the end of the day we really needed to look at the end point, whatever we come up with, we really have to be user friendly and useful to the people who are going to take it to the next step from a planning to actual implementation, and so there is a big effort, we are spending on our documentations and trying to make sure how we're going to package and structure our reports and our conceptual plan so that it will be useful and it will be easy to be implemented down the road. So those are really the five items I have in my list.

CHAIRMAN WEISENMILLER: Okay, thank you. Anne.

MS. MILLS: Okay, I'm going to try not to repeat myself too much from this morning, but I think we do – I'm also going to try to refrain from making the LTP sound like the center around everything, around which everything should resolve. But I think we do see the coordination between the PUC and the ISO as the coordination that we've worked on very closely over the last year and I think we have a pretty good plan for going forward, is really key for smoothing of the transmission and permitting bit, and I'll talk about something about construction in a second.

But just a note about LTTP and why we were hanging our hat so much on this. You know, looking at 2020, it's not just about the 33 percent RPS, it's about our energy efficiency goals, our CHP goals, the CSI, OTC, which has been mentioned, AB 32, in general, so, I think from the PUC's perspective, we really need in the LTTP to take a look at all of these policies together, what that looks like in 2020, what the integration needs are of the renewables, aside from the transmission, and what all of these costs are, so that's why we've developed these four scenarios. The ISO has not done an integration study on all of them, we're going to find out the transmission needs. We're getting the full production cost modeling from the utilities. And with that full picture, then, we think we're going to be in a better position to say, you know, is this the road we should go down? Is this the road we should go down? Are there lines that are common to all of them? Are there fossil units or, you know, a certain amount of flexible storage that is also common to all of these scenarios? Should we also be directing the utilities to invest in that so that we can integrate all these renewables that we bring on? But we need that full look and that's why we're taking the approach that we are in the LTTP. Obviously, that's only for the IOUs at this point. The scenarios we developed were statewide, and we used the best information we had, which was the information that the POUs had submitted to the ARB about their plans for RPS in our scenarios, and so the ISO, I believe, actually did a statewide analysis in their integration look. But, clearly, that is one weakness in the LTTP is that we only have jurisdiction over the utilities, the investor-owned utilities, and so our whole modeling is really investor-owned – focused on the investor-owned utilities. So, with that in mind, and Carl, I'd love to hear how we can make the PUC process more navigable since you said that that was a challenge, besides the many many appeals I made at RETI meetings, which you were subject to, about trying to talk through – this is where we see this going, this is why we think there needs to be this coordination. So, please, everyone come and participate here.

We did try to update RETI's environmental scoring to recognize some things that hadn't been included, but we got a lot of pushback on that and we reversed direction on many of those specific things. So we do really see this coordination between the state's resource planning authority and the transmission planning authority, as really crucial to getting – to identifying what we need and making that determination in the permitting process very smooth.

A few more comments on RETI. I think the PUC is very much – I don't see RETI as dead, personally. The decision was that RETI's, you know, all contracting issues aside, that RETI's work was being incorporated into formal processes, there had always been envisioned that, at the end of RETI, that these formal processes would have to incorporate the RETI information, and so there would need to be updates, I mean, Carl mentioned DRECP and the Solar EPIS, we very much anticipate and I think that letter to RETI stakeholders did anticipate that RETI's work would need to be updated as DRECP work came out, Solar EPIS, new transmission lines, so we very much hope that that stakeholder process will come back together and update that information, but I think what became clear in RETI was that there wasn't going to be a determination by that stakeholder group. When you had the IOUs and the POUs, and the developers at the table, there wasn't going to be a prioritization of, "This is going to be the one or two projects." I mean, developers weren't going to be willing to step back and say, “Okay, you can have it,” you know, “Despite the millions of dollars I’ve put into this project, I don’t actually need transmission.” And, you know, the utilities, I don’t think, were going to make that – were going to be willing to make the sacrifices either, so the way we saw things going, even though we had always anticipated that RETI could prioritize, and that would have been in the RETI mission statement, it became clear that that stakeholder group wasn’t going to be able to do it, and so it would have to be in the agency processes.

Just a quick note on construction. This three-year cycle for planning, permitting, and construction does seem very very ambitious. Assuming that we get planning and permitting down, the one thought I have on construction is that we have this Assembly Bill 1954 which passed last year, which specifically allows the PUC, even though we think this was allowable before it more explicitly allows the utilities to come in and ask for assurance beforehand that they can invest in certain preconstruction activities, even investing in long lead time equipment before they get assurance of the PUC determination, so that as soon as they get that determination they don’t have to spend a year waiting for transformers and whatever else, whatever other long lead time equipment there is, they get their determination and they can start building. And if they don't get that determination of need, they can recover the costs that they've spent. So we hope that that would eliminate some of the gap between approval and construction, but otherwise, on construction lead times, I would defer to the utilities.

CHAIRMAN WIESENMILLER: Okay, thanks. Ziad.

MR. ALAYWAN: Yeah, I'll keep my comments brief. Thank you very much for inviting me here. I'm going to focus, I think you heard a lot of good suggestions here, I'm more – I'm not a process guy, I'm more just sort of look at the results and see if the process has worked, and looking at this, if you look back in history a little bit, the cost of transmission for the ratepayer starting in the year 2000 was about $2.00 per megawatt hour. Right now, it is about $7.00 per megawatt hour, it tripled, even though the load, the consumption has not increased that much. With all this transmission, we expect that that number is going to become $14.00 per megawatt hour by 2020, the cost is going up quite a bit. Look at the ISO planning process, it's really not a planning process, that is economic project that is an Independent Transmission project that has been shut off, basically. I work with both utilities and independent

Transmission, I happen to know a few things about these projects. For example, one independent project has a permit, it actually has a permit to construct a 500 kv line in Southern California, 110 miles, and was not – and it’s a 1,000 megawatt line, $350 million, and it was not selected. And these guys have a permit. And so I look at these results and I shake my head, as a guy who has been doing this for 25 years, and you know, sort of like something is missing here. So, I don’t know what’s going on behind the doors, but I look at the result and it’s very questionable. You have another independent project that has proposed underground West of Devers, which is a very bottleneck, as you heard today, proposed underground line that goes along the railroad with basically working with the railroad and acquiring right of way from the railroad, which is environmentally friendly, which is actually cost-effective, believe it or not, with the new technologies, that wasn’t really been studied. I think, unfortunately, is we are not doing transmission planning the way I know what transmission planning is because transmission planning is basically you’re looking at various alternatives and you pick the least cost alternative, both from economics point of view, from land use, from different variables. We’re not doing that. This is unfortunately going to go to the PUC and the PUC is going to be left with the bag, trying to respond to people, saying, “Well, my project is more environmentally friendly, I’m lower cost than the other projects, and we’re going to go into this years and years of trying to figure this out.

I think, as a not just giving you the bad news, I think it’s – this is not very difficult. I think if you look at Texas, which is I happen to be involved in that process, I think the process there worked very well. They came up with different scenarios, they looked at economics, they looked at alternatives, they looked at land use, and they put it out for bid. And they selected eight entities, a few of them are independent transmission. And I don’t know why this is so complicated in California. And so I tend to think that you don’t need folks like me who are engineers/operators, and really this is not that difficult. I think the politics are very heavy in this and what this is leading to is very high costs with everybody, so that’s sort of – another point to offer, you know, as an observer into this, I think there is a lot of improvement that can be made to the process. I think, clearly, the ISO has stated that the independent transmission don’t have the right to build, own, and operate in California, I think the result of the ISO

Transmission Planning Study was not surprising because they sort of said that from the beginning, so all 40 independent projects were, you know, shut out of taking a serious look at them. So I think, unfortunately, we have to find a way, are we going to accept this regime that we have today, which is leading to higher cost, or are we going to come up with something that is more like an integrated planning, if you will, where we look at all of these things and we decide what is best for the state? Thank you.

CHAIRMAN WEISENMILLER: What is your cost of capital compared to the utilities?

MR. ALAYWAN: The cost of capital, I mean, traditionally the cost of the capital for independent transmission is a little bit higher than the utility, but the O&M and the other buckets are lower, so it kind of balances out in terms of from what I saw, different numbers, so in certain areas the cost for the independent transmission is a little bit higher. The rate of return is set by FERC, so I don't think this –

CHAIRMAN WEISENMILLER: But it is higher. So what is – is there a cost cap with the independents, or not in the bids? Are they fixed bids or cost plus?

MR. ALAYWAN: Well, the independent transmission, the folks that I've been working with, has put forward the proposal in which they would not go above 25 percent of their bid cost, so they sort of have a cap on it to make sure there is no, you know, I come in, I low bid the project, and I end up with twice as much. Of course, that’s something that’s not acceptable. I think some folks have realized that, you know, so they have put forward some kind of proposal in which they would fix costs plus a percentage, you know, fix percentage.

CHAIRMAN WEISENMILLER: Yeah, that’s not too different than utility cost estimates, which always have some contingency factors.

MR. ALAYWAN: That is correct. So it’s a little bit disturbing to see projects that are proposed by independent transmission. Not all of them are good projects, in my view, but there are a few that are very good and they ought to be looked at very seriously, and they’re much lower cost, and at least a couple of them, they have permits, and they basically really are waiting and nothing is happening, so one of the things that you have asked for, what can you do in – I mean, some of these projects can come on line two, three, four years before the approved projects, or have yet to be approved tomorrow, or whatever is going to happen, and so there is some ways where we can cut costs and bring things faster if that’s what the objective is.

CHAIRMAN WEISENMILLER: Yeah, but it has to be consistent with the tariff. Next speaker.

MR. SHIRMOHAMMADI: Mr. Chairman, Mr. Feist, my name is Darlush Shirmohammadi, I am the Transmission Advisor to California Wind Energy Association. My presentation – unfortunately, I wasn’t here in the morning, so if I’m repeating anything that was said in the morning, please forgive me.

Recently, I used a technical business magazine article, code from a Wiseman Electric Transmission Business, who said in U.S., and particularly in California, no one has the authority to have a transmission project built while everybody gets plenty of opportunity to kill it. When I read it more carefully, I said that that code was for me, by the way, that article. So we don’t build transmission for a multitude of – fast enough, good enough, cheap enough, for a multitude of reasons, and I’m going to talk about three major ones. And I’m going to offer some solutions to address one of the ones that I think we can put our arms around it; the other two, to me, are still hopeless.

The main three reasons that I see, one is we plan for transmission reactively, we go after solving transmission problems only when the need for transmission has reached a crisis stage, and it seems everybody is praying that somehow the need for transmission will go away and we can achieve our economic and policy objectives through some magical wand or something, so that’s one reason, crisis-based transmission planning. The other one is the opposition by environmental and affected community groups, which is completely understandable, not necessarily good reasons. When we’re dealing with these folks, we treat them mostly – I mean transmission developers – unfortunately, we treat them mostly as outcasts for whatever reason, and whatever is offered to them looks like clumsy sales job, that’s mainly intended to satisfy the regulators. So, eventually a settlement is reached with these groups, but it’s done at the tail end of the whole thing, it’s when you have tried everything, you have litigated everything, and so on, and eventually – I’m wondering why we don’t get them together from the beginning, maybe some regulators would not get them together in the same room from the beginning and say, “What do you want to go along with this thing?” Let them get whatever settlements that they need to reach, start getting that from the beginning, not after the years of back and forth.

The third reason is that entities in California who are involved in planning and permitting, they tend to repeat each other's work, not always, but sometimes. And worse yet, sometimes some of these entities take on an activist role in doing the job and, if they like a transmission project, somehow everything happens so smoothly around that, if they don't like it, for good or bad reasons, that things can get – everything that was done by another entity would have to be repeated, would be questioned, and everything gets slowed down. We need to make sure that these things don't happen, that they stay objective, the process stays objective, and there is no overlap.

With these three factors that I mentioned, I'd like to focus my attention on the first one, which – and I do that because I think that this is – the issue of overcoming this crisis-based planning, dealing with crisis-based planning, reactive and – I'd like to focus my attention on that one simply because I think we can put our arms around it and simply because we have mechanisms to make that happen, and in that regard, as I will present some material below, you'll see the key role that California ISO will play in that capacity. In fact, you'll see that almost the entire set of my comments evolve around CAISO.

First, I would like to talk about a ton of good things that CAISO has recently done. They came up – they studied and approved the build-out of the Sunrise Powerlink. Of course, they don’t look at the route, they look at the need from system point of view, I’m glad the route took care of itself eventually. But that was – and they did that in advance of the need coming up, and that’s what really important because, by doing it, the transmission build-out started before the crisis hit. They again did the same thing with Tehachapi Transmission Project, again, they studied it and approved it, the Board of Governors approved it, ahead of the curve, before the crisis hit, so two very visionary actions by the California ISO. They studied and approved the change of configuration of DPV2 from something that would bring fossil-based generation into California to a project that would help interconnect, integrate I-10 corridor renewable projects, again, on a proactive basis. And most importantly, they modified the transmission planning process recently to allow for proactive planning for policy-based needs, most notably renewable integration and interconnection. This is very critical because it allows us to stay ahead of the curve, I mean, based on the tariff, the implementation of the tariff on a consistent basis, which would call for development of regional least cost transmission – least regrets transmission projects. It puts us ahead of the curve. Make sure that we have transmission before the crisis hits. And, of course, all the delays are going to come later on, but at least they have started the process earlier. So, furthermore, what CAISO did, it indicated that these type of transmission, proactively planned transmission could be developed based on competition, which should lead to faster, cheaper transmission projects.

One of the most important factors in the proposal in this new transmission planning proposal, of course, was the development of least regrets transmission plan. The critical – the importance of that is not only that we're going to basically plan for transmission ahead of the schedule that is least likely to get stranded, which is a good thing, we don't want that investment to get stranded for many good reasons, but also least regrets transmission planning will lead to upgrades that benefit many renewable projects and will benefit – and will be built ahead of those projects – many transmission in many areas, and we'll build those transmission projects in time for those projects to benefit from, as opposed to coming up with these upgrades, least regrets upgrades which are mainly bulk system upgrades. At the time, as part of basically a reactive crisis-based GIP process in which these projects would basically sink very good renewable projects; as opposed to helping them, in can sink them. So CAISO has done a lot of good things to – by the way, I’m not looking for a job at CAISO, as you will see soon, you will see that I have – I am going to talk about the other side of the coin, as well – CAISO has done a lot of good things, the most important of which has been basically revamping the transmission planning process to deal with proactive planning for policy to meet State’s policy needs.

When we saw all these things happening, based on the experience and the tariff, we were very encouraged and we were looking forward to seeing the 2010-2011 Transmission Plan and what we unfortunately saw is that CAISO punted on all the proactive planning and rather than developing a proactive regional, least regrets plan, they sort of collected a bunch of projects that have come out of some disparate planning activities by utilities, by themselves, and they call it the 2010-2011 Transmission Plan, they further went ahead and proclaimed that, “Well, we have enough transmission.” Well, if we develop everything on rooftop, we don’t need any transmission. That’s not the answer we were looking for, we were looking for a good explanation of a – a good process to develop regional least regrets transmission on a proactive basis, as opposed to a declaration that we don't need any more transmission. Well, at least if you do that, do it on following your own tariff.

On the very specific basis, I noticed some of my colleagues mentioned this, we were disappointed that CAISO failed to identify reinforcements between PG&E and Edison systems and we think that there is a lot more than simply a Midway-Gregg line that people were talking about, neither in that regard. Without those upgrades, we think that PG&E customers who pay about 40 percent of all the transmission upgrades in Edison's service territory are really not going to benefit from all the renewables that are being interconnecting to the Edison system.

So, in short, and going back to the first point that I thought was playing a big role in delays in planning and permitting and building transmission, and that's sort of crisis-based transmission planning, well, reactive-based transmission planning, I think if CAISO goes and just implements its tariff, well, we have at least dealt with those issues. The other issues based on years of experience in transmission in the State, I'm not sure how successful we'll be to bring transmission developers and environmental groups together in the same room without somebody committing a murder in that or other – or ensuring that the entities that deal with planning or permitting and so on will definitely cooperate with each other enough to prevent redundancy in activities and so on. Anyway….

CHAIRMAN WEISENMILLER: Thank you. I guess the one question I have is, Ziad obviously pointed to the increase in cost for transmission as an indication, assuming that we're building lots of transmission, where you were saying that, in fact, we're not building enough?

MR. SHIRMOHAMMADI: That's right. The fact that the cost – I think what Ziad is mentioning is not saying that we are building too much transmission, we need transmission, there is no doubt that we need transmission, his point is that maybe the transmission being – I'm just conjecturing – that building transmission the way it's being built, by maybe IOUs and not by independents, is making the cost go up in this fashion. I don't think anybody can deny that we need more transmission – not only for renewables, but also for better operation of the Grid. It is well established by FERC and other bodies that, given the comparative cost of transmission vis a vis cost of generation, and the added competition that could come from having access to more renewables based on more transmission, that they actually have treated it as a no brainer, that no transmission is not an issue. Of course, there are environmental issues, there are other factors that prevent us from just building too much transmission.

CHAIRMAN WEISENMILLER: Okay, and I guess the last question for you, you had mentioned the north-south reinforcement as really being necessary. Again, looking primarily from the renewable lens, are there any other big missing projects?

MR. SHIRMOHAMMADI: The reinforcements, I mean, beyond north-south reinforcements that you talked about? Yeah, some projects that would increase our ability to interchange with our eastern balancing – neighboring balancing areas, Arizona, Nevada, and they don't have to be transmissions that go into those areas, but also transmission that could be both transmission that will be built in California and also across the border into those states.

CHAIRMAN WEISENMILLER: Okay, thank you.

MR. JENKINS: Hello, my name is Robert Jenkins. I'm with First Solar. Thank you for inviting me to be here today. I think First Solar has the unique position here being the only actual developer here at the table, but we are at heart a PV module manufacturing company, capacity of about 1,500 megawatts per year, DC this year, expanding up to 2,300 megawatts next year, 2,800 megawatts. So we have quite a bit of product to move, that’s a lot of resources to get on the ground. We’re also very active in many markets in the southwest. In the CAISO, alone, we have 2,100 megawatts of PPAs, about 4,000 megawatts in the queue right now, many more that have been in the queue at one time, but we’re at 4,000 at this point.

My career, the first couple decades, let’s describe it that way, it doesn’t sound quite so bad, the first couple decades were up to my elbows in transmission planning and, in the last decade, it’s been more focused on independent generation, interconnection, both from a developer standpoint and also from the utility standpoint and the procurement side of the organization, so looking at projects, looking at things that are important for procurement. Taking that lens and looking at the questions that were asked, I’d like to take the second one first because it’s a hard question, but I think it’s a fairly quick answer, and that is planning, permitting and construction cycle reduction to three years. There have been many efforts to try to do this and there's been some improvements overall in the permitting side, there's been some improvements in the construction side, but really, to do something in three years, you're relying on better utilization of the existing infrastructure. You really can't expect to permit a new line or a new corridor within this timeframe.

So the focus there really needs to be more on how do we either increase the capacity, or the capacity factor of the transmission lines. There's been – well, it's been maybe a couple decades ago, the big thing was to put high temperature conductors on lines, increase capacity. We pretty much played that trick out. We need to be thinking about new more innovative ways to increase the capacity of existing assets, DC light seems to be something that is picking up now, that might present opportunities for unutilized lines, but we need to be thinking about the next technology that allows us to better use the assets we have.

Also, with renewables, which are generally lower capacity factor resources, how do we increase the utilization of the lines that we have, whether it be through diversity of supplies, or there was some discussion about energy storage, the intelligent siting of energy storage such that it does increase the utilization of existing assets. But there's really no silver bullet in this.

One thing I do miss when I look at the system now vs. the system that was handed to us those three decades about was there was a more of a look toward the future in the system design. Generally, a transmission line was designed with either some mechanical strength in the line to accommodate future upgrades, to accommodate future growth, future system needs. You seldom ever built a single circuit line, you always built a double circuit line, maybe only string one side of it. I've seen a number of 500 kv lines I approved recently that are generally all single circuit, and I think we need to be looking a little further ahead of is it really the best use of rights of way to build single circuit lines and should we be thinking about more into the future, and putting those assets in the ground to allow quick response to changes because I don't think we're doing it today. We seem to have this just in time planning mentality that tends to always leave us just behind the time.

So, if we can't really speed up the permitting construction process, let's focus a little bit more on the planning side of it. What we find today and we see in the transmission queue is the planning in California is sending out missed messages. First off, the transmission incubation time is so long, it requires quite immature projects to get into the queue, you can't wait until your project matures because you'll never succeed and that's because the allocation of capacity occurs at the front end. You get in very early, you get your transmission cost identified, you get your allocation, and then you start working trying to mature your project. And somehow we need to be thinking about reversing that and how do we have a process that encourages more mature projects to be in the process, but then the process needs to move quickly at that point.

We also receive inconsistent telegraphing on siting and that causes projects to hedge their bets by putting in multiple projects at different locations, trying to anticipate really what the buyer wants, or trying to anticipate really what the permitting agencies want, trying to anticipate what the land use might turn out, so we end up with a multiple – many times the overall – just trying to address all these missed messages that we're receiving. So if we had a consistent messaging from all the entities, one that really – I'm sorry Carl left – but one that we really hear a lot is, “Well, we’d like to use disturbed lands, private lands, disturbed lands,” we’re doing a large project on private disturbed lands right now, and I’ll tell you, it’s not very easy – they’re telling you to go someplace maybe over the public lands, the public lands are telling you to go to private lands. We’re getting a lot of these kind of mixed messages, so getting that consistent. We also spend a lot of the process time and planning on cost allocation issues. There’s a portion of planning that identifies what sort of upgrades the system needs, then there’s this whole other aspect of planning that really spends a lot of time on cost allocation, who should pay what? And if we can find a way to make that more efficient, I think that will really make the whole planning cycle much more efficient in addressing cost allocation because, really, in the end the costs really go back to the end user, so do we really want to spend that much time?

I look back over the planning process where we got today and I’m really glad to see that CAISO has – I’ll call it a foundation plan, that plan I’m sure will modify as time goes, but we now have a foundation plan for renewables. It is a demand-based plan whereby it is looking at what is demand for renewables, rather than if you tried to develop a supply-based plan, which the interconnection process does, you end up with a huge plan with many lines that will never be built, now we have at least the starting point for a demand-based plan. So that is a good element of it. But we need to be thinking about the flexibility of the plan. Some of the components of the plan are really triggered by one or two anchor tenant, and we need to be thinking about what happens and be anticipating, you know, what are the contingencies that may happen in the plans and how do you address those? But having the flexibility in the plan such that we can accommodate changes when they happen, have that pre-understood, if you will. Also, when you have these plans, some aspects of the plans are quite clear, there's many developers, many opportunities, it lines up with – Tehachapi comes to mind – move quickly with those. The parts of the plan that are a little more uncertain, I think there are opportunities to keep the plan moving forward, as Anne was mentioning, getting some of the preconstruction activities done, making avenues there for cost recovery, whether it be independents or whether it be utilities, so they can go and proceed with some of these pre construction activities and be ready to pull the trigger when you need to, but if we want until everything is certain, it will take forever before it gets planned to be done.

The last element, though, I think all the planning kind of gets sideways if we ignore at the very end how – I think Tony said – about how it’s all being socialized anyway, how is this capacity being allocated – not the cost so much, we talked about that earlier, but the capacity itself? For example, we mentioned the queue being 30,000 some megawatts; if the land use and the procurement and all these other things line up, that I want the project that is number 27,000 of that 38,000 in the queue, there’s no – and there’s transmission being proposed in the area, there’s no clear line of sight how that project gets access to that transmission. And so we could spend years after the transmission is built trying to figure this out. So, here we are, we’ve rushed the planning process, we’ve got that done, and we’ve advanced the construction process, but we hadn’t figured out how to get the projects connected to the capacities being installed. So, I think some time understanding how that process would work would be well spent, as well. That’s all I have to say. Thank you.

CHAIRMAN WEISENMILLER: Thank you. I think actually what I’ll do at this stage – obviously, we’re hoping to have a round robin and we’re not going to have a round robin, I think most of the people at that end of the table got to reflect on everyone else’s comments and a couple people – this is the second panel, so I was going to ask Tony if he had any reaction to what’s been said so far.

MR. BRAUN: Just very briefly, you know, we socialize our high voltage grid in the ISO, a tariff methodology right now, and it’s frankly something that we pushed for as a POU community since the get go, in fact, it’s in AB 1890. Where we are now, though, is we are in a position where we are – we’re the generator interconnection process, at least over the last few – several years, has driven the transmission planning process, and there’s an effort to turn that around and that’s, I think, appropriate. But I think one of the things we struggle with, and I think we hear Darlush talking about the transmission investment decisions as some of these things are no-brainers, and I think that reflects that his clients aren’t paying for any of this transmission. The load is not a monolith and some of the entities are already at 33, 40, 50 percent renewables. Some of the renewables that are going in on certain parts because they can’t be delivered to other parts of the State, so at a sort of a fundamental level of, I don’t know, cost allocation, we’ve got no problem with the mechanisms that are in place right now under the tariff, and we don’t want to change them. But to then, in the planning process, sort of assume away the cost and benefits of certain projects because of that methodology, or desensitize the consideration of those costs in what we decide are the best fit projects, I think, is inappropriate, so just because we have a socialize rate doesn’t mean we should desensitize the transmission rate component as part of the decision making process as what should go forward and what are the top priority projects.

CHAIRMAN WEISENMILLER: What was your reaction to Darlush’s suggestion that we really need to upgrade the sort of north-south capacity?

MR. BRAUN: You know, I don’t know if I’m the most expert to talk to that. I mean, from a fundamental standpoint, and I listen to Carl and Grace talk about some of the west-wide desire for better seasonal exchanges, clearly I think some of the mid-state bottlenecks are going to have to get resolved, but my clients all used to have the exchange agreements with BPA, those things don’t really exist anymore because of the difference in load profiles as opposed to 20 years ago, a whole host of factors that have nothing to do with Path 26 or Path 15. So, I think my intuition would tell me, yes, that from a big picture standpoint, some upgrades to the mid part of the state and the north state, we can't just have all the transmission in one part of -- really, putting too many eggs in the basket of delivery of certain of the resources. But I don't have any empirical evidence to support that intuition.

CHAIRMAN WEISENMILLER: Okay, thank you. We're running a little late, so I'd normally go back to the sister agencies to comment, although I'm trying to avoid sort of go back through ground that I think we've covered earlier. So I was going to turn to the public comment section now. Do we have anyone in the room?

MS. KOROSEC: We do have one card from Daniel Hodges-Copple from Clean Line Energy Partners.

MR. HODGES-COPPLE: Good afternoon. My name is Daniel Hodges-Copple, and I work for Clean Line Energy Partners. Clean Line is developing one of the Interstate DC projects that was referenced earlier called Centennial West. It will transport wind energy from New Mexico to Southern California. I just have a brief comment in reference to the earlier discussion on west-wide transmission cooperation and remote resources. In line with some of the earlier remarks, utilizing renewable resources from across the west can lead to lower cost, greater diversification, enhanced competition, and a backstop in case permitting obstacles delay some in-state options. Considering these potential benefits, I think, transmission planning processes and organizations should be more open to independent developers who are often uniquely positioned to do long haul interstate projects. I think we’re moving more in that direction, but there is still some work to be done in that regard. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

MS. KOROSEC: I have one online from Ron Dickerson. Can you open his line, Donna? All right, Ron, your line is open. You had a question?

MR. DICKERSON: Thank you. It’s Ron Dickerson with Save the Foothills Coalition. I appreciate the conversation this afternoon about how the planning process might need some tweaking and improving, but I’d like to return to this morning’s panel about the existing – or I should say current analysis on where we stand in regards to transmission to renewables, specifically the ISO’s transmission planning process. It’s my understanding that there is about 16,000 megawatts of generation in the interconnection queue, the study is completed, and so I’m wondering to what extent that capacity is incorporated into the existing transmission plan and the second part of that question is, how does that fit into I guess the heart of this meeting today, and that's Governor Brown's Clean Energy Jobs Plan. Maybe Neil is still there, or Lorenzo from the ISO could answer that?

CHAIRMAN WEISENMILLER: I think those are fair questions for both the ISO and also CTPG.

MR. DICKERSON: I would agree.

CHAIRMAN WEISENMILLER: And they're both here, so, Neil, do you want to go first? And then Mo Beshir.

MR. MILLAR: Sure. Well, this is actually one of the points I touched on in my earlier presentation this morning, was that the network upgrades that were identified through previous generator interconnection work was incorporated not as the result of the plan, but as an input into our planning process to then determine what else is required and that analysis, with one small exception of a network upgrade, indicated that taking into account those network upgrades for which the study work had already been completed comfortably exceeded the ISO's share of the Net Short position that was required to meet the 33 percent RPS goal. And I have to emphasize "comfortably exceeded" because we saw the transmission that's already identified moving forward in progress as comfortably more than meeting the minimum requirements, which enabled the competition between different areas, as well as within each area. Now, that work came out of the development or the study work associated with the serial and transition and cluster studies that have already been completed. That's where those network upgrades were identified.

MR. BESHIR: The same considerations, the key assumption in the studies is really what are the goals of what are needed to meet the 33 percent, so we have in our report, and going through our stakeholder process, we've been going through the methodology on how to arrive at the transmission which is going to be needed to meet the goal which was the 33 percent for the studies, so we started with what we call the total forecasted load for 2020, which was a CEC provided, which has 285,000 gigawatt hours was what was projected at that time. Then, when you go through subtracting what was available, what was going to be made available through an existing transmission projects already in the pipeline, you end up with what we call the Net Short, which was 52,764 Gigawatt hours, so that was really the goal of meeting. Now, how you meet that and how you analyze what resources are going to be developed and used, you form the process using what is really in the queue. So you go through the queue, look at all the resources available, there was a mechanism through CPUC and CEC and the RETI process which really identified the potential resources and that was also informed from the work which was done by Black and Veatch and all that RETI process identifying the CREZ’s. So all that intelligence was used to develop the resources, but the target was really based not because we had so much resources in the queue, but what was really the need to meet the policy goal for the studies.

CHAIRMAN WEISENMILLER: Thank you. Any other?

MS. KOROSEC: I have one more online question from Jim Stewart. Jim, your line should be open.

MR. STEWART: Yes, hello. Can you hear me?

MS. KOROSEC: Just barely. Can you speak up a bit?

MR. STEWART: All right. Can you hear me now?

MS. KOROSEC: Yeah.

MR. STEWART: All right, so this is Jim Stewart speaking on behalf of Sierra Club California, and our concern is the need for comprehensive least regrets best cost, best kind of analysis, which is not happening at many of the [inaudible] [01:42:23] in the CTPG and there’s no publicly available cost analysis for the LGIA, so there’s huge amounts of projects that are costly to all the ratepayers in the state that are not being considered by the bodies. And I agree with the CPUC that this is something that needs to be changed immediately and we call upon the CAISO Board of Governors to file a new tariff and get that process changed back to the least fair cost and publicly available participatory process. The second comment that I have is in relationship to the issue of the Governor's goal. I mean, you talk about – CAISO talked about policy driven projects, well, the Governor's goal is the 12,000 megawatts of distributed generation, which 9,000 would be contributing toward the RPS, and yet the hybrid case that CAISO introduced at the very start of the day only has 3,000 megawatts of distributed generation and I want Mr. Picker to comment on what we can do to get the whole process here to be in line with the Governor's policy driven approach.

CHAIRMAN WEISENMILLER: Thanks for your comments. I would point out that the Governor's goal is 20,000 12 DG, 8,000 utility-scale. And also, I think just sort of probably good wrap-up comments, I think what you tend to find is that – okay, are we there – what you tend to find on the agency's partially history and tradition is that the Energy Commission tends to look at a lot of these issues from a land use planning lens, the ISO from a system reliability lens, and the PUC from a rates lens, and obviously when you combine all three perspectives, you probably get the total – I guess we could use the elephant analogy, but you try to get the whole picture. But each of the individual pieces have just that certain perspective of what's going on. But hopefully, collectively, we can reach the right decisions.

MS. KOROSEC: I have no more cards. Is there anyone else in the room that would like to make a comment? All right, just a reminder that written comments are due on May 24th.

CHAIRMAN WEISENMILLER: I would like to thank everyone again for their participation. We certainly have had an interesting day and looking forward to your written comments, and I'm sure our next workshop. Bye.

[Adjourned at 3:02 P.M.]