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CALIFORNIA ENERGY COMMISSION

LEAD COMMISSIONER WORKSHOP

In the Matter of:	) Docket No.
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	)
	) WORKSHOP Re: Southern
2016 Integrated Energy Policy	) California Electricity
Report Update (2016 IEPR Update)	) Infrastructure
________________________________	) Assessment

CALIFORNIA ENERGY COMMISSION

THE WARREN-ALQUIST STATE ENERGY BUILDING

ART ROSENFELD HEARING ROOM

(HEARING ROOM A)

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, AUGUST 29, 2016

1:00 P.M.

Reported By: Peter Petty

APPEARANCES

Commissioners Present

Robert Weisenmiller, Chair
Karen Douglas, Lead Commissioner
David Hochschild, Commissioner

Staff Present

Heather Raitt, IEPR Lead
Matthew Layton
Mike Jaske
Lana Wong

Joint Agency Partners:

Tom Doughty, California Independent System Operator (CAISO)
Laki Tisopulos, South Coast Air Quality Management District (SCAQMD)
Jonathan Bishop, State Water Resources Control Board
Mike Florio, California Public Utilities Commission

Panel Presenters (* Via telephone and/or WebEx)

Kendall Helm, San Diego Gas & Electric (SDG&E)
Caroline McAndrews, Southern California Edison (SCE)
Neil Millar, CAISO
John Jontry, SDG&E
Dana Cabbell, SCE
Bhaskar Chandan, SCAQMD
*Jim Swaney, San Diego Air Pollution Control District (SDAPCD)

Public Comment

Steven Kelly, Independent Energy Producers (IEP)
Gregory Blue, Cogentrix

I N D E X

I N D E X (Cont.)

P R O C E E D I N G S

August 29, 2016 1:05 p.m.

MS. RAITT: Welcome to today's Lead Commissioner Workshop on Southern California Electricity Reliability. Today's topic is reliability issues related to the closure of San Onofre Nuclear Generation Station and the phase out of once-through cooling technologies. I'm Heather Raitt, the Program Manager for the IEPER.

A few housekeeping items: restrooms are in the atrium. There's a snack bar on the second floor at the top of the stairs. If there's an emergency and we need to evacuate the building, please follow staff to Roosevelt Park, which is across the street, diagonal to the building.

Today's workshop is being broadcast through our WebEx conferencing system. Parties should be aware that you're being recorded. We'll post an audio recording on the Energy Commission's website in a couple of days, and a written transcript in about a month.

There will be an opportunity for public comments at the end of the day. We're limiting comments to three minutes each. If you'd like to make comments, please fill out a blue card there at the entrance to the hearing room. And when it's your time, we'll take comments from the center podium. After hearing from folks in the room, we'll hear from WebEx participants and then phone-in participants. And if you're on the WebEx and want to make a comment, please use the chat function to tell the WebEx coordinator you'd like to make a comment.

Public written comments are welcome and they are due on September 12th and the workshop notice provides information on how to submit comments. And with that I'll turn it over the Commissioner for opening remarks. Thank you.

CHAIRMAN WEISENMILLER: Good afternoon. I'd like to thank all the stakeholders for their participation this afternoon. And certainly looking around the dais we have a pretty full group, which again I think symbolizes really the importance all of us have taken on a coordinated inter-agency activity to deal with the consequences of the San Onofre shutdown. Obviously, we're very far along on this, but part of it is not being complacent, but seeing where the major actions are and make sure we're staying on track, so looking forward to the update today

This is -- we've done this every year now, since San Onofre went out. This is the first time in Sacramento instead of within Los Angeles, which hopefully guarantees a more cooperative AV system. (Laughter.)

COMMISSIONER DOUGLAS: Hi. This is Commissioner Karen Douglas with the Energy Commission. As the Lead Commissioner on IEPR this year, I'd like to join the Chair in extending my welcome to everybody participating in this workshop today, so thank you.

COMMISSIONER FLORIO: Mike Florio, California Public Utility Commission. This is a continuing story, looking forward to the updates on where we stand, and what other efforts we may have to add to get to the finish line. But this has been a very cooperative effort for a number of years and I hope that that continues to the finish line. Thank you.

MR. DOUGHTY: And Chair Weisenmiller, Tom Doughty with the California Independent System Operator. I too want to celebrate the collaboration we've enjoyed over the last couple of years, four years I guess it is now.

I've sat in on virtually dozens of phone calls on SONGS mitigation measures. And I've seen tremendous cooperation from the agencies as well as the utilities and others. So I know we'll keep that going into the coming months and look forward to a healthy discussion on where we are. Thank you.

COMMISSIONER HOCHSCHILD: David Hochshild, I'm the Lead for Renewables at the Energy Commission. Welcome to everybody.

MR. TISOPULOS: Laki Tisopulos, South Coast Air Coast Management District. Thank you for inviting us to be part of this very important proceeding. Keeping the lights on is a very important issue for my agency, Southern California, and for all of us. It's not just a health and safety issue, but it's also an environmental and an economic issue. So we are looking for forward to a very productive and informative workshop. Thank you.

MR. BISHOP: Jonathan Bishop with the State Water Resource Control Board. Once again happy to be here and looking forward to hearing what the updates are and providing our input into how to move forward.

MS. RAITT: Okay Great. So our first panel is on the Update on Activities Identified in the Draft Plan. And the first speaker is Kendall Helm from San Diego Gas and Electric.

MS. HELM: All right, good afternoon. My name is Kendall Helm. And I'm the Director of Origination for San Diego Gas and Electric. I serve in the team responsible for acquiring all energy and capacity needed to serve our customers.

I would like to thank the California Energy Commission, the California Public Utilities Commission, and the California Independent System Operator for their leadership in monitoring progress needed to ensure electric reliability in Southern California, with the retirement of SONGS and once-through cooling technologies.

Before I address SDG&E's Procurement Update since last year's workshop, I would like to take a moment to highlight our progress in meeting another important state goal of reaching a 50 percent Renewable Portfolio Standard by 2030.

Last year, in August of 2015, SDG&E was the first utility in California to announce that 33 percent of the power delivered to customers over the previous 12 months was from renewable sources. This number has risen to 35 percent for the full year 2015 and we expect to reach a 45 percent RPS by 2020. And this is just coming from supply sources that are already contracted or under an ongoing program.

As such, we believe SDG&E is well positioned to meet the state goal of the 50 percent RPS by 2030. I mention this today because we're very proud of being a clean energy leader in the state and because our RPS position will necessarily shape our preferred resource procurement plans going forward.

Turning to our RFO status, as you know, the CPUC authorized SDG&E to procure between 500 and 800 megawatts of local resources in response to the retirement of SONGS and OTC technologies. The amount is reflective of capacity needs in 2022, but we have local shortages projected to begin in 2018, after the Encina Power Plant is scheduled to retire.

For this authorization, the CPUC approved our 500 megawatt PPA with Carlsbad last year. The original schedule was for this power plant to be online in November, 2017, but with the decision under appeal, NRG now expects that plant to be online in the second quarter of 2018. Through our conversations with NRG, they have stated confidence with this timeframe assuming there is timely resolution of the appeal.

In March of this year, we also submitted two preferred resource contracts from our 2014 all-source RFO. We submitted a 20 megawatt energy storage contract that is scheduled to be on one in 2019, and an 18 megawatt energy efficiency contract scheduled to start in 2018.

We are also in the midst of running a second RFO for preferred resources only and expect to have our short list identified in October. We're in the midst of analyzing bids for that RFO right now, but we've received very good participation from both demand side and supply side sources. We plan to run additional preferred resource solicitations as needed to meet our 2022 requirement. And we plan to use a measured approach. And we're doing this to ensure we continue to capture the benefits of market innovation and development along the way.

Two other procurement efforts, for local capacity and energy that I would like to mention, relate to preferred resources.

First, in response to the May, 2016 CPUC resolution, authorizing expedited energy storage procurement, we were able to leverage the current RFO in order to solicit interest from parties that could provide energy storage to be online by the end of this year, or first thing next year.

We were able to successfully leverage this process and sign up two energy storage contracts, a 30 megawatt energy storage contract that will be built at our Escondido substation and a 7.5 megawatt project that will be built at our El Cajon substation.

With these two projects, we will have contracted for a total of 107 megawatts of energy storage, which puts us about 65 percent of the way towards our 165 megawatt energy storage goal by 2024.

Second, we're in the midst of procuring renewable energy from local sources for our Green Tariff Shared Renewables Program. This is the program where customers can sign up for a special tariff that accords with 100 percent renewable energy from local projects or where local developers can bid in a project and sign up customers directly to ascribe to their project. We have already procured 20 megawatts from a solar PPA for the special tariff and we're running a solar solicitation for developers to bid in customer-ascribed projects under the enhanced community renewable solicitation. Though the program's only 59 megawatts right now, we think this is an important program, not only to help with local reliability, but also to provide customers with additional choices on their energy mix.

Finally, we were asked to comment on any relevant insights about local reliability from the procurement perspective. The one I would highlight today relates to our focus at SDG&E on looking to the future, where procurement is optimized through the IRP process. As you know, SB 350 requires the CPUC to identify optimal portfolios to meet combined objectives of reliability, cost effectiveness and achieving the state's GHG reduction goals.

We will support and collaborate with all stakeholders in development of IOP process. And at SDG&E, we're preparing for our procurement activities to be affected by this legislation. We're very much in support of Integrated Resource Planning and we expect we'll be doing more procurement where both demand side and supply side resources are competing. We're seeing this competition play out successfully in our preferred resources RFOs and we look forward to developing this approach further.

This concludes my remarks and thank you for your time.

MS. RAITT: Thanks. Next is Caroline McAndrews from Southern California Edison.

MS. MCANDREWS: I feel so short back here.

Good afternoon. I was asked to come and present about the status of our LCR RFO as well as provide an update on the Preferred Resources Pilot.

So I'll first start off -- and the two are very much related -- so I'll first start off with information that you probably are well aware of. We launched an RFO back in 2013 timeframe and four preferred resources as well as energy storage. And what you see on the slide there are the totals of which we have signed contracts for. We also included in that solicitation gas-fired resources, gas-fired generation and that's also listed there.

In 2014, we filed our application, which again you've heard this last year, and then since then in November of 2015 we did obtain a final decision for Western LA Basin. And there have been several appeals and rehearings. And so as of June 16th, right now, what we have is approval of those contracts and the CPUC denying the application for rehearing as well as an additional authorization to acquire an additional 170 megawatts of preferred resources.

So with that, the real implication here is that the developers are going off and they are actually seeking customers to sign contracts with them and develop the resources. Some of the online dates, because of the long process that it has taken have been rescheduled to be a little later, but the online date is still expected to be 2021.

Why this is important, and it relates to the next topic, which is the Preferred Resources Pilot is that some of those contracts were scheduled to come online in 2016 and also 2017 in support of the Preferred Resources Pilot. Which is a SCE Initiative, which really wanted to look at how are preferred resources performing, will they deliver what's needed, when needed, for as long as needed? And so really just focused on can we acquire them? Can we deploy them? And can we measure their contribution and count on them just as reliably as we would gas-fired generation?

And so there's a lot of value to this project. Again, this is a recap of last year, so I won't spend a lot of time on it, but since then what we've also done is focus certain portions of that, of our project, to support the Distribution Resources Plan and the demonstration projects associated with that. We are acquiring quite a bit of additional resources which I'm going to cover on the following page.

So maybe as a recap, in terms of our milestone, early in 2018 our objective really is to demonstrate our ability to acquire. And that also means establishing a pipeline for obtaining these resources very locally and deploying that mix of resources. And that's a challenge sometimes, because when you're really concentrating on a local area, you'll have limited customers and a lot of developers. And I'm going to talk a little bit about what we've done in order to address that issue. And then obviously to measure their performance capabilities, which again in some cases is very straightforward and in other cases it's not.

So we're following this approach of design, acquire, deploy and measure. They are actually occurring all at the same time. They're feeding into each other and engaging a lot of stakeholders along the way.

So in terms of progress, what you see here on this slide is a lot of information about how much we actually have acquired. And when I say acquired, that means it's also deployed in some cases or under contract. So in terms of the amount that's actually deployed it's about 93 megawatts. A lot of it is EE.

And we've got also in the DG area, not something that SCE actually contracted for, but another utility had signed a contract for a CHP unit that is connected into the area and maybe to recap, the area is down in the Southern Orange County area: two substations, Johanna and Santiago. A customer set of about 250,000 customers. So it's a large area, but obviously small within our territory. So what we have is about 93-94 megawatts of deployed preferred resources.

The DSM programs are the key contributors to these megawatts. And so the real advantage of having our DSM programs is we're able to actually get the resources out very timely. When you look out to the megawatts expected, in 2017 and 2020, those tend to be the contracted resources. As you know, we have -- actually they all are all contracted resources -- what we have, we go out for a solicitation, and then we have to go in for contract approval. So there's some timing that takes place there and some uncertainty associated with that. But right now, I can say that by the end of 2017, we expect 155 megawatts online. So that's very good.

By the end of 2020, we're expecting 181 megawatts. And I also want to say that we have a PRP RFO 2, where we have sought an additional 100 megawatts of demand-response, energy storage and DG and hybrids, which are a combination of energy storage and solar. So we expect to be signing those contracts very soon. We're in negotiation phase right now. And we anticipate having another -- at least 100 megawatts of resources that would be again coming online by the end of 2020.

So this provides us with quite a bit of information. By the end of 2017, we expect to have sufficient information, relative to how well are these preferred resources performing.

Also that we have some challenges there. When it comes down to energy efficiency, I'm going to talk about that in a little bit on the next slide, that is one of the areas that's real challenging.

The other part to this is that in order to really make that good determination we need to have the infrastructure set up, so that we can actually get some run time on these preferred resources. With a bulk, a large bulk, not coming on until -- actually if we look here, we've got POS, which we're going to be measuring. We're going to have more energy efficiency, which is a challenging area to measure and then some more DG coming online.

In energy storage, we're going to look to see how well these preferred resources perform, but we need to design the infrastructure. And so some of the delays in getting the LCR contracts online has caused some delays in some of our measurement.

So now I would like to talk a little bit about some insights and opportunities. When we look at the PRP region, what we have here is -- this is the demand in the region. You can see it's driven by non-residential and it peaks somewhat in the middle of the day. We've been acquiring resources focused on the attributes that serve this need here in the middle of the day. We have then since focused some of our more recent RFOs, PRP RFO 2, and actually included some additional attributes that are seeking resources that fill the later in the day needs, so that we can address some of the circuit needs.

So when we go out for the RFO to focus on the attributes versus the resource type has been very helpful. The developers then could come in and they could provide options for what might fill those particular attributes.

Here's an example of the circuits and the hours. And you can see that some of the circuits have different needs, different time of day needs.

As we go through this process, we're also learning quite a bit. Our distribution planning is getting more and more refined, so that what this was defined in the 2014 timeframe. Now when we look into the 2015 timeframe into the beginning of 2016, some of these circuit needs have changed. And so what is anticipated as certain growth in some areas has not come to fruition. And other areas have also come up as growing.

So it's a very dynamic situation, dependent upon the environment, the economic environment, customer needs, customer drivers. And so when we're really focusing in, down at the distribution level, the dynamics require us to really refine how we look at forecasting, as you all know.

Urban versus solar, when we look at the particular environment that we're in, it's a suburban area. We've got a lot of building owners and tenants. Some of those building owners are not interested in solar development. They are actually -- the penetration level at this particular area is about 3 percent; it's under 5 percent of solar.

Now we expect that through natural adoption that solar amount is going to increase at the residential customer and slowly on the commercial side. But you saw the commercial is driving the peak. And we're not seeing that adoption. And there's a lot of different reasons for why building owners don't want to adopt solar.

And so what we did is we worked with Clean Coalition to identify some of the potential barriers. And put together this guide to have some dialogue with some of those building owners as to why they might want to consider. And some of the mitigating activities they can take if they've got concerns about deploying solar on their site.

Regarding the customer, as I said we've got a finite set of customers, 250,000 customers, and a lot of developers ascending in the area. And so any time we get into this local procurement we have a lot of customer confusion. We've got our programs, our customer programs. We've got developers who are either saying they do have contracts or they don't have contracts, or they're saying they have contracts and they don't have contracts.

And so what we did was we worked actually with the developers, who -- these are our LCR contractors, contracts that we've signed. You can see that we've actually put our logo, the little statement on front, about how they can go greener. And here are the developers who we've got contracts with. And so it's a way of really partnering and trying to -- for us to be successful in these LCR contracts by showing that these really are the developers we are working with.

Demographics, that owner-tenant issue the I discuss. So some of the things that we've tested out, and it has not taken off as far as we've wanted to, but something called owner direct incentives. In the past, owners of buildings would have to work through their tenant in order to get incentives for energy efficiency. We have now a process where a building owner can directly go and apply for that incentive and not have to work through the tenant.

So this is something that we tested out last year. It is a good process. We now have to do more advertising so that we can get more participation. And this will help with, again, increasing that energy efficiency goal by having access to the owners who actually want access to the incentives.

The other items that we've done, is we've actually added a locational incentive that was authorized back in end of 2014, so we've been using that for 2015 and 2016. It's a $50 per KW kicker for all custom programs. And we don't have a threshold.

The last thing that we've done in terms of enhancing customer participation is really look at can we do something with LED tubes? And we've paired up with some developers on a tube retrofit and got that approved to broaden out the extension of that offering to many more customers. It's a lower cost way of changing out light bulbs with LEDs as opposed to CFLs. Typically you have to do more. And we're also working on troughers also.

The other area that we're doing is really looking at our resources and our readiness of our grid. And maybe I'll speak a little bit about energy efficiency. We took a deep dive into a set of energy efficiency customers who -- they implemented measures. About 800 implemented measures when we try to see how much saving we can get and cull it down to a group that would give us some meaningful measures at their meter level; it came down to about 60 customers. And with those 60 customers we drilled in a little further and worked with FirstFuel to develop this baselining approach with actually baseline -- that's the green line here -- they baseline what their energy use is, was, and then going forward, they project out what it would have been.

And then this black line here signifies the installation of the energy efficiency measure and what we were able to see at the customer's meter level, without billing modeling, is this energy efficiency savings. The challenge is that when we actually ran this across those 60 customers, now albeit it's a small sub set, we saw that for the savings of energy efficiency at the customer meter, about 30 percent you could actually see a savings.

So when we think about distribution planning and relying on energy efficiency as a resource that we want to use as to potentially defer some sort of system upgrade, circuit upgrade, we really need to have something that will manifest itself like this.

Now all energy efficiency is good and we're seeing that overall trend decrease in use, but when we're looking at specific deferral, we're really honing in to see what customer set, what building type and what energy efficiency measure gives us the combination that can ultimately give us this kind of a saving on a regular bases. And if those customers, building types are paired on a circuit that is in need of some upgrade, can we then target those particular customers?

The other area that we're looking at is behind the meter resources. The bulk of the solar is unmetered in this particular area. It's at customer sites and it's not something that the utility can see. So what we've done is we've actually worked with Clean Power Research to design a methodology of predicting what the energy production was. And we correlate that to the actual production for the few metered systems that we have.

And we've got good correlation, not great correlation. It's about 8 percent of error. But if we are at least crediting a certain amount of this, even if we discount it by that level of uncertainty, we are able to provide some credit, higher credit than is previously assigned for that solar production.

So some of the next steps, we are completing our RFO 2 and are going to be seeking contract approval for those contracts. We are continuing our acquisition through our DSM programs and then again continuing to build up that measurement process. Thank you.

MS. RAITT: Thanks. So next we'll move on to Updates on Transmission System Additions. And this is Neil Millar, from the California Independent System Operator.

MR. MILLAR: Good morning. And thank you for the opportunity to speak today. I will provide a bit of an overview of the reliability of the issue and reliability of the area and touch on some of the issues involved. Some of the other speakers will be touching on some of these details with a bit more precision, but I'll be providing more of the overview.

Just to set the stage, the reliability in the L.A. Basin and San Diego areas have been impacted by the initial early retirement of the SONGS Generating Station, as well as the anticipated retirement of the once-through cooling resources in the area and more recently gas supply concerns.

On this map, I've just provided a bit of an overview of the area, of the transmission system we're dealing with, and the location of the various generation. And primarily we've been dealing with a basket of both voltage stability issues and thermal transmission line loss issues. And these different issues tend to trade places back and forth as to which is the dominant issue as various solutions come online.

But we do need to focus as well that even with the procurement that's been authorized we are looking at reduction by more than 50 percent of the gas fleet in the area as well as accommodating the loss of the San Onofre Nuclear Generating Station.

To accommodate the loss of the generating station in the first place, we were looking at a basket of resources that were tied as well to the mitigation plans that were moving forward to address once-through cooling generation retirements. So it really was a broad solution, involving many different aspects. The resource procurement that you've already heard about was a large part of it.

There are also a number of transmission projects moving forward. In particular, a significant number of synchronous condenser projects focusing on addressing voltage stability issues as well as a group of other transmission projects that provided both voltage support as well as addressing some of the thermal problems in the area.

The three transmission projects that I'll speak to in particular are the Imperial Valley Phase Shifting Transformer Project, the Mesa Loop-in Project and the Sycamore-Panasquitos Transmission Line. Those projects, working together, were allowing us to address a number of issues in the area. So it's not as easy as tying any one issue to one solution. There's a large amount of interplay between the reactive support devices, the resource procurement and the transmission projects as they come online.

This map just provides an indication of where those various projects are located. The Mesa Loop-in Project up more towards the upper left in yellow. The Synchronous Condenser Project scattered throughout and of course the Sycamore-Panasquitos line being the yellow line towards the bottom of the map.

Overall, the mitigations that were put in place or identified and were moving forward have been proceeding well, but there are a few areas where potential concerns are now being encountered and are emerging. We already heard about the potential delay of the Carlsbad Energy Center, with the potential in-service date. If it delays into Q2 2018, we believe that that's likely generating now the need to extend the Encina compliance, OTC compliance date, beyond its current target of December 31st, 2017. That will be talked about in more detail by the second panel.

The other two issues I wanted to touch on are the Mesa Loop-in Project that Southern California Edison will speak to in more detail here today. It is under environmental review proceedings with the CPUC. If the in-service date is delayed beyond Q2 of 2021, we think that it's likely that either Redondo Beach or the Alamitos Generation OTC compliance dates would need to be extended. The Redondo Beach generation is more effective at mitigating the overloads that we would be dealing with. There are challenges there. There are other issues that I believe Dana Cabbell will speak on later, around the Alamitos generation. So there will need to be a conversation about which generation would actually be required should that delay take place.

The last project I wanted to mention was the Sycamore-Panasquitos 230 kV transmission line. This is also currently under review by the CPUC. It currently has a March 20, 2018 in-service date. If it is delayed beyond that point, than it may increase the reliability need beyond what Carlsbad could provide in the San Diego area. So that's another one of our major concerns.

So our next steps are that we are refining our analysis as part of our 2016-17 transmission planning process. We will be updating the near-term, mid-term and long-term local capacity requirements for the area. The near-term and mid-term studies are done primarily to inform state agencies with the long-term being part of our overall long-term transmission planning process.

Now we will be looking and are looking at sensitivity assessments, considering the scenario where the

Mesa Loop-In Project is delayed, given the narrow margin there. The updated analysis will be available by the end of 2016 and included in the draft 2016-17 Transmission Plan, that we post each year by the end of January.

One last issue I should touch on is that we're also monitoring the progress with the South Orange County Reliability Enhancement Project, inside San Diego. While the project is designed to address the more localized reliability issue and the alternative applied for, approved by the ISO, and applied for by San Diego Gas and Electric would not normally be part of this discussion. Some of the alternatives being put forth could impact the reliability of the overall area by impacting the transfer capabilities between the L.A. Basin and San Diego, so we're watching that closely as well.

So that's my update for now and we'll look forward to the questions that Dana and John Jontry can answer. Thank you.

MS. RAITT: Thank you, Neil. So next is John Jontry, from San Diego Gas and Electric.

MR. JONTRY: Good afternoon. My name is John Jontry. I'm the Manager of Grid Planning for SDG&E. And my group has the responsibility for performing the Ten-year NERC the reliability studies for the SDG&E bulk power and sub=transmission system. So today I will discuss the status of some of the bulk power projects that we're currently working on, both planned in-service and then some that are being proposed.

Just a quick overview, this is a map of the SDG&E transmission system. The 500 kV, as you know, comes from the east, from Imperial Valley and then we're connected to SCE to the north at SONGS. This map indicates the number of the projects I'll be talking about: Orange County to the north, Artesia and Sycamore PQ and then some of the voltage support projects.

Also I've broken the projects into basically three types: voltage support projects, new transmission lines and then substation projects, both new substations and then major upgrades to existing substations.

Neil discussed this earlier. We have a rather large number of voltage support projects planned for both our area and for Edison. These projects are basically designed to provide voltage stability to the system, prevent voltage collapse during extreme system contingencies, and sort of ride herd on the voltage during normal system operations.

Within our territory, we have five locations where we're adding voltage support. Four of those locations have synchronous condensers and one is a Static Bar Compensator or an SBC.

The first synchronous condenser installation was at Talega. It's in-service right now, has been in-service since August of last year. Upcoming projects are a one synchronous condenser at SONGS, two each at San Luis Rey and Miguel and finally a 300 MVAR SBC at Suncrest, which is being done by an independent developer NextEra Transmission.

The in-service dates for the synchronous condenser projects are all sometime in 2017, hopefully. The Suncrest Static VAR Compensator initially had an in-service date of 2017, but I think it's somewhat indeterminate right now. I believe it's currently under review by the CPUC.

For new transmission lines, we have three 230 kV lines, bulk power lines, currently under development. Neil will discuss the Sycamore PQ line. It's currently in the CPCN proceeding. We're hoping to get a proposed decision and approval by the fourth quarter of this year. And the current expected in-service date would be early 2018.

Two other lines under development are the Mission to Penasquitos line and then the second Miguel to Bay Boulevard 230 kV line. Both of those are under development. The Mission to Penasquitos line, the final configuration and route will determine or will be determined at least in part by what comes out of the

Sycamore PQ proceeding. So we don't have a final route or design for that. The Miguel to Bay Boulevard #2 is also under development. So right now, we don't have a good in-service date for either of those, but it'll probably be in the 2019 to 2020 timeframe.

Finally, for the bulk power substations, we have several to talk about. The Bay Boulevard 230 substation, which went into service earlier this year, is a new 230 to 69 kV substation and was basically put in place to replace the generation at South Bay when that generation retired at the end of 2009.

The Imperial Valley Phase Shifter, Neil also mentioned that one, we finished major equipment procurement and testing. The phase shifters are soon to be on their way to San Diego. And we anticipate a in-service date of May 2017.

South Orange County Enhancement Project, or SOCRE, it's currently under review by the PUC, under a CPCM proceeding. We're hoping to have a proposed decision sometime at the end of this year with approval first quarter of next near. It includes both a substation upgrade to San Juan Capistrano Substation from 138 to 230 and also includes eight miles of double circuit 230 kV from Talega substation to San Juan Capistrano. I think right now our tentative in-service date is somewhere in the

2020/2021 timeframe.

One thing I'll mention, going back to the map, one, one that doesn't appear on the list, but the Artesian 230 kV Substation is also a bulk power substation we're adding at the existing Artesian Substation. It will provide a new bulk power source to the Poway Load Pocket, which is this area here in sort of North suburban San Diego. That one's -- I believe we just submitted the PEA and I think our tentative in-service date is 2019 or 2020.

Finally, I'll just touch on a couple of projects that we'll be proposing in the ISO reliability window for this cycle. First one is the Southwest Power Link HVDC Conversion Project. We've also submitted it to the CAISO and West Connect Interregional Planning processes earlier this year. It is a proposal that would convert the Southwest Power Link from North Gila to Imperial Valley Substation into Miguel to a high voltage DC line from its current AC configuration for the purposes of increasing the throughput capability of the line and also improving system control by making it a flow control device instead of a free-flowing AC line.

And the second project is a new 230/69 kV substation at the existing Pala Substation. This is in sort of Northwest San Diego County. And the purpose is to provide a new bulk power source to the -- so the northwest

69 kV system that's feeding all of the area up around Camp Pendleton, Pala and so forth.

That's all I have, so I welcome any questions. Thanks.

MS. RAITT: Thanks, John. So next is Dana Cabbell, from Southern California Edison.

MS. CABBELL: Thank you very much. Good afternoon. Dana Cabbell, Manager of Transmission Interconnection Planning at Southern California Edison.

And I'm going to go over the two projects that Neil highlighted as the projects that were identified and proposed for the -- to meet the SONGS retirement and OTC retirement. And also I have a slide on some status of some other major transmission projects in our area.

So the first is our Mesa Substation project. It's a 500 kV project. This map will just to give you some orientation. The red is representing 500 kV lines and substations and the blue represents the 230 kV substations and lines within the Western L.A. Basin.

The blue, the 230 substations on this map, about half our load is served through those substations. And when we peak, the power comes from the 500 kV system, through the 230 system to serve that load. And so as the OTC plants and with SONGS out, obviously we are starting to see more flows from the 500 system down to the 230, more imports that are coming in, into the Basin.

And so Mesa Substation was approved and to go forward to basically increase the transfer capability from the 500 system down into the Basin; currently Mesa is a 230 to 66 kV substation. So we would be adding a 500 kV portion and looping in the Vincent to Mira Loma 500 kV line, that's part of the Tri-Tip Project.

So the status right now is we did file back in March, in 2015. We filed for a PTC. A draft EIR came out and was issued. And we are hoping for a final decision in December of this year, so that we can meet the 2020 operating date.

If the substation, or the decision is delayed, causing the substation delay, project delay, we were looking at potentially needing to extend some of the OTC contracts. Here, I'm seeing Redondo. I know Alamitos was also mention, which is workable. But with Alamitos we do need to do some additional studies, because there could be a short-circuit duty issue at some of our 230 stations in the area. So that would require some additional analysis.

For the Reactive Support Project, the Santiago Substation, which is in the South Orange County area, we have a synchronous condenser project, 225 MVARs; it kind of goes hand-in-hand with the one that San Diego's installing at SONGS Switch Yard. Right now, we have selected a vendor. It is a turnkey project. So we expect the construction to -- the substation construction is near completion and we should be commencing the project, phase two of the project, in 2017 and have it online by the end of next year. So that seems to be right on track.

Some of the other major projects that we have going on, West of Devers Upgrade, which was just approved. We just were granted the CPCN. We are working to get the ROD from the BLM and we will be construction with an upper date of 2021. As you recall this project is to help integrate and deliver renewables from the Riverside East portion of the system.

The Lugo-Mojave, Eldorado-Lugo 500 kV Series Cap Upgrade. These were two policy driven projects that the ISO approved. We're doing some detailed engineering. We're going to submit the PEA. It's under development at this point and time. And then we will start construction third quarter of 2017.

Alberhill Substation, that's a reliability project to help serve growing load down in the Temecula-Menifee area of our system. And we filed an application in 2009 and we're hoping to have an approval in quarter four of 2017, with construction in 2018.

And then Santa Barbara County Reliability Project, I know it's not a transmission, it's a sub-transmission project, but it is a pretty significant project for the Santa Barbara area. And we did receive the PTC and now we're waiting on the Coastal Commission for their permitting for a small portion of the project. And we should start construction by 2017, with operation in 2018.

And finally, with Tehachapi Renewable Transmission Project, we're at kind of the end of the road with this project. The last piece is the undergrounding of the 500 kV portion of the Vincent-Mira Loma line. So the three miles of the 500 kV underground is actually going through commissioning this week. And we're hoping to have it fully operational by the end of this year.

And that's it. Thank you very much.

MS. RAITT: Great, thanks.

Moving on to Generation Permitting, we have Matt Layton, from the Energy Commission.

MR. LAYTON: Good afternoon. My name is Matthew Layton. I'm with the California Energy Commission. I'm an Engineering Office Manager in the Siting Division. The Siting Division provides the first review of thermal power plants 50 megawatts and greater. So I'm going to run down the power plants that are in front of us right now in the Energy Commission, both at the staff level and at the Commission level.

Most of the power plants you're probably familiar with. We did include a couple of power plants in Ventura that we'll get to. We haven't really talked much about Ventura County, but we put them in there because they're close enough, I think.

The first power plant is Pio Pico. It was approved back in 2012. The units are undergoing commissioning. We expect commercial online either September 1 or September 8th, I believe. It does have a Power Purchase Agreement. It's a pretty simple project located down near the border near the Otay Mesa plant.

The next one in San Diego County, is the Encina Power Plant Replacement, called the Carlsbad Energy Center. They have a license right now and they are doing some final tank demolition and site prep. I think construction has been delayed until October of 2016.

The El Segundo Energy Center, replacing Units 1 and 2, the project was approved back in 2013 -- oh excuse me -- approved quite some time ago. It is online and operating as of 2013.

The second part of that replacement at El Segundo, Units 3 and 4, which are the two units in the foreground on that photograph, the project was nearing approval. The owner of the project requested that the petition be withdrawn and the proceeding has since been terminated. I think that's about two or three weeks old.

AES Alamitos, the project is in-house right now. There's about 1,900 Megawatts at AES in the Alamitos Generating Station. The proposed project is about 1,000 megawatts, 640 has a Power Purchase Agreement, 400 megawatts would be under simple cycles that may get built, but the Energy Commission is looking to permit the entire 1,000 megawatts. We expect a decision in 2016 that may -- I think the most recent schedule that came out last week, it may be as late as January of 2017.

AES Huntington Beach, similar, about 640 megawatts of combined cycle. That particular portion of the new facility does have a Power Purchase Agreement. The owner is also looking to install 200 megawatts of simple cycle plants, units. Again, the decision was expected in December of this year. It may spill over into 2017.

AES Redondo Beach, the project is in suspension. The city and the owner are in negotiations what to do with the project. The facility that was being proposed as a replacement project for the existing generating station would have been a combined cycle, it does not have a Power Purchase Agreement.

A couple of projects inland, not once-through cooled, these are replacement -- this is a replacement project here. There is an existing LM5000, small gas turbine. The owner is proposing to replace that combustion turbine with a 100 megawatt LMS100. I think some batteries are also being proposed onsite. They are not thermal generation, but it is part of the project since its being located inside a building on the site. So we are looking to review that and it's somewhat delayed in the review.

This is a small power plant exemption, which is 50 megawatts and greater or 100 megawatts or less. This one comes in at about 70 megawatts net for the site. I do not believe it has a Power Purchase Agreement. And we do not have a schedule giving some of the new information coming in about the batteries.

Another project that is going to file with us, with the Energy Commission this October, is in Stanton in Northern Orange County. It has an integrated battery, which would be part of the project review and two LM6000s.

Up in Ventura County there's the NRG Puente Power Plant, which is actually a replacement of Units 1 and 2 of the Mandalay Generating Station. It's in review right now. The final decision is expected in April of 2017. Mandalay Unit 3, 130 megawatt peaker will remain onsite. The two existing gas boilers would be dismantled as part of the new project.

Another project that just came in, it does not have a Power Purchase Agreement. It's about 20 miles away from the Puente site or the Mandalay site. It's located in the county, near the city of Santa Paula. It would be about 275 megawatts. It would have clutches on each of the combustion turbines and would have batteries onsite. The batteries would not be integrated into the combustion turbine part of the project, but since it would be proposed at the same time, the Energy Commission will be reviewing the batteries.

And acronyms -- the only other thing, Ormond Beach is not on the list, because we do not have an application in front of us. That's 1,500 megawatts in Ventura County, that's part of the OTC shut-downs. It's likely to shut down. Thank you.

CHAIRMAN WEISENMILLER: Great, so a few questions.

First, I would like to really congratulate SDG&E for their progress on renewables. Obviously when the Renewable RPS Standard passed, I think they were roughly at zero. And now they have surpassed their brethren. So again, certainly great moves and encourage you to continue doing more. Hopefully you can pull along some of the other utilities in California, particularly some of our POU friends to high levels like that, so great.

I think with Edison, I guess the thing I found most interesting in Caroline's presentation was basically what are you trying to do in the area of basically the distributed resource plan demonstration projects? It's sort of a new component. Certainly timely, to try to build that in to what you're doing there is to really focus on the DG part of stuff.

MS. MCANDREWS: So as you know there's I guess an open proceeding on that, so I'll have to be careful in terms of what I say.

CHAIRMAN WEISENMILLER: Right.

MS. MCANDREWS: PRP RFO 2 identified some potential circuits that could be used for deferral -- are in need of upgrade -- and so some of those attributes that we listed in the RFO were for resources, if we can get resources, at those particular circuits. And so we had a very successful RFO and we anticipate getting some resources that can contribute to that demonstration project.

Also, within the DRP is an area of testing high penetration of DERs. And that is actually being done at Johanna Jr, which is a bravo level substation and also Camden substation, another bravo level substation. And again, through our acquisition process, we are acquiring resources in that area.

So we're also now with LCR developers going out, we are having discussions with some of the LCR developers to try to encourage them and help them with some of our customers, like for example with that flyer, to encourage them to go into these particular areas because obviously the more resources we can get in that area, the less we'll have to go out and acquire additional resources. So we really want to leverage our activities and not over-procure if we don't need to.

CHAIRMAN WEISENMILLER: Good. Yeah. No, I'll certainly encourage SDG&E to think about ways they can also move forward on preferred resources that leverages some of the potential DRP processes.

MS. HELM: Hi. I guess I would just mirror some of the things that Caroline mentioned. I know I think one of the first things that we'll be looking at is procurement for the Distributed Resource Plan pilots. I know, in the Integrated Energy Distributed Resource proceeding, that Commissioner Florio has been overseeing as well, we're looking at what kind -- how can we test out some competitive solicitation process for some of these early pilots for the DRP? So I think that'll be the first step.

CHAIRMAN WEISENMILLER: Great. Actually on sort of a less happy topic, when Governor Brown announced his Clean Jobs Plan, as part of his election, he had a goal which was roughly to cut the PUC's permitting time for transmission in half. There's not been much progress on that, I guess listening from today's conversation. I know President Picker has launched GO-Biz to try to figure out some degree of process reform.

But God Bless, how do we get some -- I mean how long has SOCRE been around? When did it start?

MR. JONTRY: Let's see. It was approved by the ISO in --

MR. MILLAR: The '10-'11 Plan.

MR. JONTRY: Yeah.

CHAIRMAN WEISENMILLER: Yeah, I thought it was always baked into our SONGS planning that was going to be done and now it's --

MR. JONTRY: So far (indiscernible) yes, it was in the 2010-'11 Transmission Plan.

MR. MILLAR: Yeah, right.

CHAIRMAN WEISENMILLER: Yeah.

MR. JONTRY: Yeah. It's been -- I think the CPUC application name was complete in 2014, I think. I think I have that in my presentation here. I took it out, but I believe the application was complete in 2013/2014 or something like that. So it's been pending for at least that long, yes.

CHAIRMAN WEISENMILLER: Yeah, wow.

MR. DOUGHTY: Chair? I had an observation on that. These projects we're talking about now, we kind of consider them legacy projects. They've been around awhile.

Recently, we've constituted a new working framework, with the permitting team at the PUC where the ISO and the CEQA team come together more frequently, share projects in their early form, so that surprises and shall we call that information that doesn't flow very well, gets handled early. I think we're going to see improvements going forward.

Will it come down into the Governor's objective timeframe? I don't know, but we are seeing improvements in the engagement between the ISO and the CEQA team. And Neil and his team deserve a lot of credit for leading that. So I'll leave it with that.

CHAIRMAN WEISENMILLER: Yeah. I would just point out we have two-and-a-half years left, so we need to make lots of progress on process reform in this area fast. So that, I mean if you look through the Governor's Clean Jobs Plan we've pretty much hit every milestone. But I mean this is like a zero if not negative, so I think certainly I'll talk to President Picker about what we can do to try to help move things along more.

MR. DOUGHTY: I had another question on a different topic. We heard here, from several of our speakers, about some of these projects that are in a bit of jeopardy: Carlsbad, Mesa Loop and Sycamore Penasquitos being three.

This is the first time, I believe, in these hearings that we've actually talked about an OTC deferral. And Jonathan, a lot of this will land in the lap of the Water Board.

I guess I asked the question, are we collectively in a position now to establish a plan to manage those deferrals? And are there -- I have only to do -- maybe some speakers that will come later in the day will speak to this, but are we in a position to do what we need to do now to take steps to do that for the first time?

Jonathan, you may have some observations to share?

MR. BISHOP: Well, as time has gone on we've gone from this is a small possibility to a greater possibility to reading ahead, it looks like an imminent possibility.

The advice that I have given many times in the past, and will continue to give, is the policy was designed with the idea that the SACCWIS could make these recommendations to the Water Board for greater liability delays and the need for those. And that that process should be instituted by the SACCWIS as soon as possible, so that there's enough time.

If it's short enough, and you look at the -- Encina has a potential of being online in March, that is a potentially a 90-day delay, which doesn't require a Board action to facilitate, which could be done in short term. But March is at the end of the 90 days and if there's any more slippage, we might be in a bad place. If we've not started that process, which will take potentially a year to go through by the time you convene the SACCWIS or the interagency working group to make a recommendation to SACCWIS, the SACCWIS to consider it and make a recommendation to the Board, the Board to consider it's a fairly lengthy process to go through.

I think that the Board took this consideration to heart when they adopted the policies, so that they're ready to act on it. But I would caution -- I was going to do it later, but I'll do it now and again later, which is that the boundaries around any extension need to be well defined. The Board will have a lot of trouble adopting an extension for an unknown period of time or without a known solution to that problem. And so those two pieces have to be in place as we move forward.

CHAIRMAN WEISENMILLER: So, I think certainly we're looking for recommendations from parties going forward on how to tee this up. And I would assume one of the IEPR recommendations in this area would be to start the process, so that we're prepared.

MR. JASKE: Chair Weisenmiller, can I ask a couple of questions?

CHAIRMAN WEISENMILLER: Sure.

MR. JASKE: This has to do with the issue of a delay in Mesa Loop-in. Both Neil and Dana have identified that if Mesa is delayed that could itself lead to a second OTC deferral with Redondo Beach or Alamitos being candidates. I guess I'm curious first to know, since both of those are relatively large facilities, are we talking about the entirety of their capacity or some small fraction of their capacity if Mesa Loop-in was delayed?

MS. CABBELL: You can start and I'll --

MR. MILLAR: I'll take the first cut. In looking at these it's not the same number in both cases. The Redondo plant is much better situated to be more affective. So we'd be looking for a material amount to generation from both, but much more if it's Alamitos instead of Redondo. I don't know if Dana has more precise numbers, but I was hesitant to provide a tougher number now when we're currently updating our analysis on that.

MS. CABBELL: Right, yes. Because Redondo is a 1,300 megawatt plant and that's why we focused on that one, because it is in the right area to make the relief that we need for LCR in that area. For Alamitos, we haven't really studied that, because as I mentioned the amount of generation or the number of units on will depend on the system short-circuit duty or concerns that there could be if we put too many units on in that area in conjunction with the repower of Alamitos in Huntington Beach. So we not pursued any type of studies along those lines.

MR. JASKE: Okay. As sort of a follow-up or parallel question -- the information submitted by AES to the Water Board earlier this year as part of the annual compliance or implementation plan, maybe that's the right way to say it, says that Redondo 7, I believe, is going to retire in 2019 to provide the air credits, so that Huntington Beach can actually go forward. So that's pushing 500 megawatts right there.

And of course there's the overarching issue of the fate of Redondo Beach as a generator. And as I understand it, there's only a contractual agreement that's supporting it through May of 2018. So after that, it's -- unless of course there is an extension, there's no clear mechanism for the remaining three units to be around.

So I guess it seems like if you haven't decided to study Alamitos it would be worth considering tackling that subject.

MR. MILLAR: Yes. And we'll be doing our analysis looking at both units, or both plants I should say, but there are trade-offs on both the effectiveness of the different plants as well as the issues that Dana referred to.

MS. CABBELL: Right. And so once we understand what amount of -- especially at Alamitos -- is where I'm most concerned. Once through the ISO studies we have identified oh, we need this amount of megawatts, these number of units, then we can go ahead and run our short-circuit duty analysis to determine if there's any further impact.

MR. JASKE: Okay. Thank you.

CHAIRMAN WEISENMILLER: Just a follow up. Oh excuse me, Mike.

Just to follow up, so Neil looking at the three projects that are sort of struggling to meet the timelines, what's your relative ranking of importance among those three?

MR. MILLAR: I think I'd challenge arguing priority, because putting it bluntly, we need all three.

The impact of the Mesa Loop-in is a bit easier to isolate from the Sycamore-Penasquitos interaction with Carlsbad. So the Mesa Loop-In Project, we believe to be relatively straight forward given the physical circumstances of the project. That affects the Alamitos versus Redondo discussion, so clearly to us that's something we think shouldn't be an issue. That we're concerned about the timelines this far out and what looked like a healthy lead time is being eaten up. So in terms of permitting issues that's one for us that looks like we should be able to avoid having to do this, but the path forward right now isn't clear.

With the, as we said in the San Diego area, with the Carlsbad-Encina interaction, the Sycamore-Penasquitos Project has the risk of requiring us to go beyond what Carlsbad -- even if Carlsbad came in the Sycamore-Penasquitos Project could cause a requirement to be greater than Carlsbad. And we're not aware of any mechanism right now that would allow Carlsbad and a piece of Encina to stick around. So I would say that's also a serious concern.

When we look at the Carlsbad -- the situation with the courts -- that looks like something that there isn't a lot we can do. We need to let that process run its course and the mitigation is unfortunately fairly straight forward, which is to keep Encina around until Carlsbad can move forward.

So I think that just talking this out, clearly the transmission projects are the ones where we think are more within our collective ability to do something about and could mitigate some of the other risks.

CHAIRMAN WEISENMILLER: How serious is SOCRE's delay?

MR. MILLAR: Oh, SOCRE delay is more of an issue to the local reliability issue within the South Orange County. Our concern with that project is that some of the alternatives that are being considered or that have been put forward by others for consideration could actually compromise -- it would be a negative. It could compromise the reliability of the area by tying two systems together at a particularly bad part. In the meantime, the people in the local area are the ones taking the risk while that situation stays as it is.

I should probably turn to Mr. Jontry to talk about that.

MR. JONTRY: Yeah, well that's basically correct. Yes. Yeah, I mean that project is primarily to serve the South Orange County load pocket. It's about 4 or 500 megawatts of load in the southern portion of Orange County. The project as we proposed it really enhances the reliability in that local area.

It doesn't really affect the larger San Diego area or interface between SDG&E and Edison, except like as Neil mentioned some of these other alternatives that involve looping in some of the lines that connect CL Path 43 from SONGS up to Edison. If some of those get looped into the 138 kV system in Orange County then it can affect the transfer capability between San Diego and Los Angeles.

And that can impact the import capability of both areas. So I think that's the larger issue.

CHAIRMAN WEISENMILLER: If we have a problem there, how long is the load going to be out in Orange County?

MR. JONTRY: Without getting too deep into the weeds, the Orange County is fed from a single 230 kV-138 kV substation. If you had a catastrophic loss of that substation, the load would be -- we wouldn't be able to serve load in Orange County or our portion of it for a long period of time, weeks -- weeks, or months.

CHAIRMAN WEISENMILLER: Okay.

MR. JASKE: Okay. And a couple of questions for Caroline, so in your presentation I was particularly interested in your comments having to do with energy efficiency. I guess this was on slide seven. And you indicated that the 2017 target of 37 megawatts was going to be very challenging, or at least that's what I heard. Could you clarify whether it's an issue of customer recruitment or an issue of once recruited will they perform as expected?

MS. MCANDREWS: So as I indicated, what we've been doing so far is really measuring the effectiveness of seeing Grid level changes at the customer's meter, the AMI meter, using the programs. When we look at the contracts that came in from the LCR contracts, the measurement processes, again it was essentially set up the same way using an ex-ante approach similar to the programs. And so what we intend to do with those contracts that come one is put them into our monitoring system and look at the customer's meter to see if we're seeing Grid level savings.

Now energy efficiency from an LCR standpoint is having a load modifying effect, so there is a value to that. Can I quantify it? No. Not easily, because there are a lot of factors that go into it obviously: customer behaviors, economics and just the operations of the facility. When we are looking to use these resources potentially for distribution deferral, we have a different measurement philosophy. We want to see some net savings, so that we can then defer a potential upgrade.

And that's where the challenge comes. So are we seeing a system-wide benefit from energy efficiency? Absolutely. Can I see it at a very local level? Not very easily.

MR. JASKE: Okay. And maybe this is an overarching question for many of these resource types, but maybe in particular focus on energy efficiency. To what extent does the PRP process, in general, is it correct to think of that as incremental savings over and above what would have happened with Edison's customer programs anyway, or is it sort of a targeting of the level of saving Edison hoped to achieve, focused in that particular electrical geographic area?

MS. MCANDREWS: So the genesis of the Preferred Resources Pilot was to address a load growth of about 300 megawatts from the customers in that local area. So if you consider a baseline to 0-300 megawatts we are totally -- the pilot is agnostic in terms of where those resources come in. So we count on our programs to bring in resources.

So our energy efficiency programs, DR programs, anything that's incremental to what the beginning state was in 2013. So through that period, our customer service programs have brought in about 20 megawatts of energy efficiency. That's just through the customer service programs, our customer programs.

And so we get them from our programs, we get them from Power Purchase Agreements, we get them from any other type of utility initiative, DOE projects, we don't care. So what we're trying to do is count the number of megawatts from 2013 out to 2021 and get 300 megawatts of deliverable megawatts, which means that if you get 60 percent from solar or 20 percent from solar, then you have to acquire more in order to meet that 300 megawatt need.

MR. JASKE: Okay. One last follow up. So if given the size of that area and the residential, commercial, industrial mix of customers that are there, would Edison have expected to have gotten somewhere in the vicinity of 40 megawatts worth of energy efficiency if it had just continued running normal programs or would it have been much less, like 30 or 20?

MS. MCANDREWS: Yeah, so the business as usual programs, from energy efficiency, we would have gotten about 6 megawatts per year. We have put emphasis in that area of marketing, customer engagement. And so we've been getting about 16 megawatts a year -- actually, let me take that back. We've been getting about eight to ten megawatts per year. So we've gotten over the last couple of years about 60 megawatts. And what you're seeing now is an additional 4 or so that we've been acquiring.

So extra energy has caused the amount of deployed energy efficiency to be greater than the business as usual.

MR. JASKE: Okay. Great. Thank you.

CHAIRMAN WEISENMILLER: Yeah, actually, one other one. Caroline, you had talked about having difficulties in part of the pilot with consumer acceptance on renewables. Is this proverbial covenant issue with Irvine Company or what?

MS. MCANDREWS: So the challenge is with many building owners. They don't see it as their "business".

They are concerned about having some infrastructure or power plant on their facilities that they're potentially liable for, have to maintain. There are a lot of various concerns that they have. And that's why we tried to capture what those concerns would be and to have some dialogue with the developer. It's a guide meant for them to have with the developer and asking the developer how they could potentially mitigate those concerns that they have.

CHAIRMAN WEISENMILLER: Thanks.

MR. TISOPULOS: Can I ask a question? Ms. Cabbell, in one of your slides relative to the 500 kV line you used the phrase "if delayed." So can you clarify for me what are some of the impediments? What are you referring to, the ongoing CEQA analysis right now or are there any other issues associated with the approval of the process?

MS. CABBELL: You're speaking of the Mesa Project?

MR. TISOPULOS: Yes.

MS. CABBELL: Yes. It's the CPCN proceeding. If that is delayed beyond the end of this year, there's potentially -- or there would be a delay in the project operating date. It might not meet the 2020 date that's needed. So it would result in looking at extending some of the OTC contracts for, as we were talking Redondo and Alamitos.

MR. TISOPULOS: But to the best of your knowledge is the analysis proceeding according to plan or are there clouds on the horizon?

MS. CABBELL: Well, I have to be cautious, because it is an ongoing proceeding. So it is going through its process right now. The draft EIR has been -- was issued and now they're working on the final EIR. So we're just hoping that it can go ahead and be issued and a final decision be made by the end of this year.

MR. TISOPULOS: One more question, so the Sentinel Project that was successfully built, is it helping the situation or is it too far away to assist the South Orange County, San Diego or perhaps South Coast reliability issues?

MS. CABBELL: I'm sorry, what --

MR. TISOPULOS: The Sentinel Project out in the desert?

MS. CABBELL: The Sentinel Project?

CHAIRMAN WEISENMILLER: You know, when we were doing the SONGS analysis that was -- in terms of I think the ISO had gone through in terms of how much capacity -- San Onofre is a specific location. So how much generation could help? And it turned out that one, I think there were a couple of projects that came online, it's just the locations were bad in terms of deliverability. Was that, correct Neil?

MR. MILLAR: That's correct. The Sentinel Project doesn't help with the local issues that we're dealing with here. It's too far east.

MS. RAITT: All right, so thank you very much to our panelists on the first panel. And I'd like to invite you to go ahead and take a seat in the audience and ask the folks on the second panel to go ahead and take a seat on the front tables.

So our second panel is an Update on Contingency Mitigation Analysis and Contingency Measures. And the first presentation is by Mike Jaske and Lana Wong, from the Energy Commission.

MS. WONG: Hi. I'm Lana Wong. And I'm going to present the analysis we did using the Local Capacity Annual Assessment Tool. This is our second annual update. It's a screening tool to support contingency mitigation decisions. We published a staff report on the 2016 IEPR website, which describes how we've updated the tool for this cycle.

So in today's presentation, I'll be going to over the purpose of the tool, the methods assumptions, the baseline results we produce, sensitivity analysis as well as a couple of scenarios that we produce, and lastly our findings and conclusions.

So what is the purpose of the tool and why did we develop it? In part, we wanted to develop annual projections of resources versus local capacity requirements for Southern California. We felt that looking on an annual basis over the ten-year planning horizon would help determine the timing and nature of a short-fall. It would be sort of an early warning signal that if there were any problems, we'd know sooner rather than later. And it would give us more options on resolving any problems that we find. What we've said is that any issues surfaced by the tool would be confirmed by a power flow study, which potentially could lead to recommendations to trigger mitigation measures.

And so in the last cycle, the tool largely worked as envisioned. What we found is deficits occurring earlier than studied by the ISO, in part because they don't study every year of the cycle. And we recommended that they run power flow and stability analysis for the year 2021, which they did in the 2015/2016 TPP cycle or that's the Transmission Planning Cycle. And the results of their analysis basically confirmed our findings that the deficits were occurring earlier than 2025.

This is just a chart which you've seen in some of the other earlier presentations, which of the areas of focus and were focused on the L.A. Basin and San Diego areas. And those are the areas that we cover in our tool, as well as the subareas West L.A. Basin and San Diego sub areas.

So LCAAT, it's essentially a spreadsheet tool built in Excel. It's a low-resolution model. The input assumptions are those taken from the 2014 LTPP and also the 2015-2016 TPP cycle. We may have had to do some mapping of data to get it down to the local area and subareas. We've essentially produced a tabulation of resources versus requirements by local area and subarea and then what the resulting surplus or deficit is in each year.

And so we've just gone through an update where we've made comprehensive updates to the tool and selectively to some data as needed. And those are maybe in some of the sensitivities if we didn't have updated information, we may have used the same data as in the last cycle.

The advantages of this tool is that as a low resolution model it's easy to run. We can run many more cases than you could using the in-depth power flow and stability modeling. But then the disadvantages are that there's a loss of accuracy in using this tool. But as we mentioned, it's a screening tool and that's essentially what it is. It's an early warning sign, but we'd still recommend in-depth studies be done if warranted.

So the next couple of slides I'll highlight the assumptions that were updated, the demand forecast we've updated to the Energy Commission 2014 IEPR Update. We've also updated some demand-side assumptions like the additional achievable energy efficiency. There were some minor updates to the IOU PPAs in there. We've also updated the local capacity requirement values to the latest ISO published values for 2016-2020, 2021 and 2025.

We've also made some updates to the demand-side adjustments. And those, we assume a one-for-one megawatt reduction that if there is a demand-side program, it would reduce the local capacity requirement by one megawatt.

For resources, we've updated to the 2015 NQC list. There's some minor updates on the IOU PPAs. We've also updated to the 2015-2016 RPS Portfolio, using the trajectory case. And it largely is the same as the last cycle, but just minor updates to that portfolio.

We do have retirement assumptions in here. We're following the State Water Resource Control Board OTC compliance dates. There's some age-based retirements and those are based on the LTPP assumptions for retirement years. Like gas-fired resources have a 40-year retirement assumption. And then we take a look at contract-based extensions. So we took a look at the PUC contracts database and extended any of the age-based retirements if there was a contract in place.

So the local capacity requirements, as I mentioned we used the latest published results available, and these requirements could be modified by demand-side programs like energy efficiency, behind-the-meter DG, and behind-the-meters storage. If there were any transmission subsystem upgrades, not included within the assumptions for that study year there may have been an adjustment there. I think in this cycle we don't have any of those, but I know in the last cycle there were some that fell into that category.

Okay, so now to look at the results of our analysis. So this chart shows the surplus deficit results. So essentially, we're taking the tabulation that I mentioned earlier. We're looking at what the local capacity requirements are, comparing it to total resources available in the area, and then calculating the resulting surplus or deficit. And so we're showing this in megawatts for the five different areas of interest.

So in this chart, we've got the combined L.A. Basin, San Diego areas in the dark blue or dark royal blue. The L.A. Basin is the red line. West L.A. Basin is in green. The San Diego IV is in purple. And then we have the San Diego subarea in that light blue color. That's all on its own shape.

So just looking at this chart what we find is that surpluses exist in most areas through 2020. The results for the key years are largely in line with the ISO study results.

We can see that the OTC retirements that occur in the year 2020 that we could see that surplus drop off in the green line. If you look at the green line that's West L.A. Basin, what you can see is that area where much of the OTC is located in Southern California that at the end of 2020, that surplus diminishes and we end up with a deficit in 2021 that essentially grows out through 2025.

And to give you some idea of what assumptions are in here, so we do, as I mentioned, the OTC retire at the end of 2020, so we see the deficit in of 2021. But the Edison PPAs are included in here. So we do have the re-powerings for Alamitos, Huntington Beach and their preferred resources in the analysis.

The San Diego subarea, what you can see the light blue line, in that particular area the OTC retirement is at the end of 2017. We've heard earlier that there could be a potential delay, but basically the results in here capture that Encina retires at the end of 2017 and Carlsbad comes online. So Encina is 960 megawatt project and Carlsbad is 500 megawatts. And so what we find is that in 2018 there's a small deficit.

And looking at San Diego, that deficit appears to persist in most years of the study period. And again as I mentioned these results are largely in line with the ISO study results for the key snapshot years that they run.

Let's see what else, so when you look at the results and we see okay, there are deficits. There's a gap. How can we close the gap? So I thought I would just highlight what the ISO published in its 2015-2016 TPP Study.

So in the San Diego area, what they indicated is that if San Diego procures preferred resources, the 140 megawatts that we heard earlier that's out for solicitation if they procure that with additional storage, that could eliminate the deficit in San Diego. And so we find that that is true and to be the case that if you did procure this additional amount, somewhere in the neighborhood of 200 megawatts, that would eliminate the deficits in San Diego.

In West L.A. Basin, what was proposed is if Edison procures its additional authorization -- so they had about 2,500 megawatts of PUC authorization and their PPAs total somewhere in the neighborhood of just above 1,800 megawatts. I believe they have about 170 megawatts more of preferred resources that they need to procure to meet the minimum levels, but that still leaves additional unused authorization, so if Edison procures additional resources and also demand-response -- the term that the ISO uses is repurposed -- some of the demand-response in West L.A. Basin. And what repurposing means is to make it eligible to meet local capacity requirements. That it needs to be fast enough responding to meet local capacity requirements.

So those were a couple of proposals that the ISO made. And there was also a possibility of some minor transmission upgrades that could potentially help close this gap.

So in addition to the baseline results, we recognize that although they are carefully prepared, many of the assumptions are subject to uncertainty. So LCAAT's a tool that is easy to run, additional sensitivities, it's not as time consuming or labor intensive as running the power flow analysis. So we ran a number of sensitivities and we created them, trying to look at a plausible range of alternative assumptions around the baseline. And then how those would impact the surplus or deficit on each of the areas.

So the next two slides cover the list of sensitivities that we covered. And essentially all of the ones listed, except for one, were the same ones that we ran in the last cycle. The report provides detail assumptions about how we produced these sensitivities. And I'll just give you a little bit of information about the new sensitivity that was created for this cycle. And this is the peak hour shift sensitivity.

So the agencies have recognized that with the increasing penetration of the behind the meter solar PV, that the peak could be occurring in a later hour of the day than what is assumed in the Energy Commission Forecast. So what the peak hour shift sensitivity captures is that the load could be higher than what's assumed in the Energy Commission Forecast, because the peak's occurring later. And it also captures that there may be less capacity available from the solar PV in that later hour.

So another note about the sensitivities that some of these are demand-side sensitivities and some are supply side. Some will make the surplus deficit worse and some will make them better. So there's a range of sensitivities that were run.

So the two areas that we're going to take a look at are the West L.A. Basin subarea and the San Diego subarea results. And both of those areas had deficits in the baseline study. So the two sensitivities that we're showing are essentially the boundary sensitivities. So the 2015 IEPR demand is one boundary case. And the high-demand sensitivity is the other boundary case and all of the other sensitivities fall somewhere in between those two cases.

And so what we see here, again, there surpluses in the early years and we see that surplus drop off after the OTC retirements at the end of 2020, and then we see the surplus diminish over time. So the blue line is the baseline case. And then the green line is our high-demand sensitivity, which shows that the deficit occurs in the same year as in the baseline case 2021. But the deficit is just worse than the baseline case.

And then at the opposite end we have the red line, which shows the benefits of the lower-demand forecast from the 2015 IEPR demand. And in that case, that eliminates the deficit in all years of the study period.

And so as we looked at the 2015 demand sensitivity and we noticed that even in the early years, there's quite a difference than the baseline case. What we found is that there's no single driver that is accounting for the lower forecast. But I can highlight some of the differences in the 2015 forecast than what is in our baseline case. That there is an increase in demand-response, there's an increase in non-PV self-generation at the peak, there's different economic and demographic drivers. There's more recent data on historical behind the meter PV penetration. There's more recent actual electricity data, so both peaks and energies data are updated.

And then there's also a redefinition of the Edison transmission access charge area. So the boundary conditions are different in this forecast than what's in the baseline case.

So the next set of results we'll look at are the San Diego subarea. And this particular area has a shape all its own. Its OTC unit retires at the end of 2017. So we have the Encina plant retiring at the end of 2017 and Carlsbad coming online to replace it.

And in the baseline case, we have San Diego's PPAs and to date, it's a small amount. I think its somewhere in the range of around 40 megawatts, but as mentioned earlier today, they have a solicitation out for another 140 megawatts of preferred resources.

So the blue line is the baseline case. The green line is the higher demand. And in that case, we see that deficits occur initially in the same year as the baseline case and continue to grow larger by the end of the study period. The red line is the 2015 IEPR Demand Forecast sensitivity. And what we see is that the deficits are eliminated in all years of the study period.

COMMISSIONER FLORIO: Just a quick question? For the green line, the sensitivity with high demand, is that from the 2013 or the 2015?

MS. WONG: So the higher-demand case would be from the 2013. And so that is half a percent higher growth per year. And it is based on the 2013 forecast, so it's based on the baseline, the forecast that's in the baseline case.

COMMISSIONER FLORIO: Thank you.

MS. WONG: So in addition to running the sensitivities, which changed a single variable, we also ran a couple of different scenarios. And so in the scenarios, we were able to combine multiple variables into one scenario that looks at the changes in one single case. And so that you'll find is that some variables can be offsetting, while others can basically move the surplus or deficit in the same direction.

So we came up with two alternatives scenarios, the high surplus and the pessimistic case. And in the high-surplus case, we've got the 2015 IEPR Load Forecast and we've combined it with the peak hour shift variable. And that one is more offsetting to the 2015 IEPR Load Forecast and moderates that reduction in the load forecast.

In the pessimistic case, we've combined three variables, high load, partial AAEE saving and per generation loss due to early retirements. And in that particular case all three of those variables tend to move and make the deficit worse.

So we chose variables. In choosing these, we tried to construct a plausible scenario, but you can combine any of the ten variables that were mentioned in the sensitivity analysis. You can combine those in any particular way to come up with a different scenario.

So again, I'm going to show the West L.A. Basin subarea and the San Diego subarea results. And so here, for West L.A. Basin, we see the similar shape, surpluses in the early years, the OTC retirements in 2020 and the diminishing surplus to deficits in the baseline case and in the pessimistic case. So the baseline case is in blue and the pessimistic case is in green. And then the red line is the high surplus case, which eliminates deficits in all years of the study period.

This is the chart for San Diego. And here, we've got the baseline case in blue. The green is the pessimistic case, which we largely followed the same shape as the baseline case, just that the deficit grows larger by the end of the study period. The red line is the high-surplus case and in that particular case deficits are eliminated in all years of the study period.

So looking at the baseline versus the scenarios, what we find is some scenarios will follow the same shape as the baseline pattern, but others may deviate slightly. We can see that both in West L.A. Basin and San Diego that we see the impact of the OTC retirements on the surplus and deficits. And what we find is that the scenarios have quite a wide range.

So to conclude, our baseline results for the key years are largely consistent with the ISO power flow study results. What we find is that there are deficits in West L.A. Basin between 2021 and 2025 after the OTC retires. We find for the San Diego subarea that there are deficits in most years of the study period. By looking at sensitivity analysis and the scenario analysis that we find alternative assumptions can eliminate the deficits or increase the surpluses.

So some findings and recommendations, we believe the ISO should study to the year 2018, which they currently are. And as mentioned earlier today those results should be available at the end of this year. We believe they should continue to study the year 2021 as well, due to the large number of OTC retirements that will occur at the end of 2020.

Then for the CPUC, we believe that they should review the surplus or deficits of local capacity requirements for West L.A. Basin and San Diego subarea to determine whether there's sufficient procurement authorization, whether that has been granted or actually implemented. And then we also encourage them to release the 2013 to 2015 evaluated energy efficiency savings estimates as soon as possible and devise a realistic range of the EE projections.

The last evaluated results are for the cycle 2010 to 2012. And what we found in those particular savings estimates showed that the peak savings to energy savings was much lower, like I think 40 percent lower than projected. So we think it's important that we continue to look at these savings estimates.

And then we also believe they should look at the impact of the peak shift on capacity ratings, because if the peak is occurring the later in the day there may actually be less capacity that you can count on from the solar PV than is being counted on in our current studies. And that concludes my presentation.

MS. RAITT: Thanks, Lana. Next is Mike Jaske, to discuss proposed contingency mitigation options.

MR. JASKE: Good afternoon. For the record, my name is Mike Jaske with the Energy Assessments Division, Energy Commission staff.

So in this presentation I'm going to be getting an overview of the two types of mitigation measures that the interagency team has developed to date. An OTC deferral request to the Water Board we talked a little bit about already, and a new generator development option.

Both these were discussed at some level in the workshop a year ago, but we've refined our ideas and are reporting to you this afternoon. Our written report has been prepared and is docketed. And if people want copies it's out on the table. And at the very end, I'm going to provide a little bit of an example about the LCAAT results might be used to decide when and if these measures are to be triggered.

So there's some terminology here: contingency, mitigations options and triggering. Let me try to give examples of what each of these three are in the context of the things we're talking about today.

So the contingency example is we're going to have a delay in the replacement power plant for an OTC facility. Think Carlsbad.

The mitigation measure, obviously, is a potential delay in the compliance date for the OTC facility, namely Encina.

And triggering, that's the process of determining if this delay in the online date is sufficiently firm and that there are adverse enough consequences that the mitigation measure, namely deferral of the compliance date, really should be initiated. That's how we're using these terms.

So the interagency team has developed this sort of basic framework with these three components. We're continuously monitoring the development of projects and trying to keep track of programmatic activity in terms of impacts of energy efficiency or DR development or DG, etcetera. We're trying to have a suite of mitigation measures developed and on the shelf, ready to be implemented if and when they're necessary. And we're apprising agency leadership regularly of our results.

So let me turn for a while now to OTC deferral -- three or four slides. There has been discussion in some PUC forums by interveners, about deferring OTC facilities on a long-term basis, perhaps even an indefinite basis.

The energy agencies worked very closely with the Water Board back in 2009 and '10 to develop a compliance schedule that tried to match what we understood, at that point in time anyway, about projects that were in the pipeline. And the Water Board modified its original compliance date schedule to take advantage of that procurement and planning information that we provided to them.

So where it was pretty clear there was a resource already being considered and maybe even permitted that was given a relatively early compliance date. And where we didn't have any idea how certain plants were going to be delayed, those got pushed back to the end of the compliance date schedule of 2020.

Reinforcing what Mr. Bishop said earlier, as a staff person involved in all of that, we need to be very careful to the way and when and how we make compliance date deferral requests. Unless they're really extraordinary circumstances, we, the staff team, expect the OTC deferrals are for a short period, one to two years and that's it.

I think Mr. Bishop mentioned this a little bit. But let me reinforce it. The whole idea of compliance date deferral to assure reliability is not a violation of the policy. It's central to the policy. It's built into the policy, in the two forms that he mentioned. There's this sort of emergency-scale deferral that the ISO can initiate on its own and then for longer-term delays, the whole SACCWIS process.

All of that is built into the policy its self. So the process we may be going through -- talking about today and may actually be starting later this year, is contemplated from the beginning of the OTC policy.

The SACCWIS body, the Statewide Advisory Committee on Cooling Water Intake Structures was composed of all the statewide agencies that seemed to have something relevant to contribute. So Water Board, Energy Commission, PUC, ISO, ARB, Coastal Commission and the Lands Commission, all have some kind of handle on one or more of these OTC facilities. And that body operates as a formal advisory body to the Water Board, operates in public, follows Bagley-Keene.

There are five items highlighted in red here that are fundamental to the deferral request: specificity, assure compliance, use existing processes, be timely and recognize consequences. We worked these out with the Water Board staff and executive management. And that process of considering and implementing an OTC deferral request is now written out in that staff report that I mentioned earlier, at the beginning of my presentation.

And again, reiterating what Mr. Bishop said earlier the assure compliance is probably the most important of these to me. We need to have a specific mitigation measure that is -- or excuse me -- a solution that we can say directly to the Water Board, "Delay this plant for one year. This final permanent solution will come into play at the end of that period of time and the OTC plant will shut down."

Here's the schedule that has been worked out with the Water Board staff. All of the items that say 30 - 45 days, etcetera, add up to about a year. The very first line, the analytic stuff that's on the shoulders of the energy agencies primarily is highly variable. So it all depends on the complexity of the situation, the ability to rely upon analyses that already exist, the need to conduct new ones. And I think it's become clear in today's workshop already that the ISO has decided that it will conduct new analyses. And so we're likely not to have those until the end of this year. And then we'll be triggering a process that looks like something like this in terms of elapsed time or various steps.

So there's a few remaining issues that still need to be resolved even though the majority of the deferral process is clear. In general, it's possible that two different ways of deferring OTC compliance dates can happen.

One is through the owners themselves. LADWP has already done that. Early on in the OTC process they were unhappy with the schedule that they were provided, pulled together a convincing package, presented it to the Water Board, obtained some delays. That might still happen in the case of OTC owner that was really intent on a fix to an existing plant, not just shutting one down and replacing it with a new facility.

Moss Landing comes to mind. Dynegy seems to clearly want to do some physical changes to those facilities and prolong their life. If for some reason it was going to take a little longer than the current compliance date schedule, perhaps they would initiate a delay request and have to justify that to the Water Board.

More central to our circumstances, of course, is where there's a reliability issue the owner of the facility can't be expected to understand a reliability issue. It's up to the energy agencies to put forward such a deferral request.

Let me turn to the new generation option then. So a year ago, at the comparable workshop, there were these three options presented to you. Shortly after the conclusion of that workshop, the interagency team decided that options one and two would be dropped. And we'd rely upon option three, which is to rely upon the existence of a pool of projects that are already permitted, but don't have power purchase agreements therefore they're not going to go forward. But should there be a necessity for a new facility to take the place perhaps of one that's fallen by the wayside for some reason, then we could trigger one of these. And having already been permitted it would only take the procurement process and actual construction to come online.

And so these three steps of this slide outline the essence of this new generation option: create and continuously monitor a pool of developer initiated projects that have received permits, understand where those are in terms of their permit lifetime, be cognizant of any changes in direction that local air districts have received in terms of ambient air standards or other things that might jeopardize one of those permits still being valid. Take that into consideration in terms of the viability of the pool.

If analysis, LCAAT, ISO power flow studies, other information implies that we need to select a new generation project, then Step 2 comes into play. Utility selects a project from the pool. There may be some issues about how perfectly matched any one of those are to the particular problem, but that's the pool that exists and have to choose which one or ones to go forward with. There may be some modifications that need to be done to such a permit or the permit of the facilities that are selected. That needs to be happened. And then utilities submit the PPA to the PUC for approval.

Once the PUC approves that, then of course the equipment is ordered and developer selects the contractor to build it. It's built and comes online.

This is our best understanding of the timeline associated with these processes, so the Energy Commission staff monitoring the pool doesn't take any time. But if there's an initial analysis that suggests that triggering is appropriate, then we need to have that confirmed. That'll take a few months.

Then the various steps associated with the project selection itself and any tuning up of the permit and then finally the construction period itself.

In aggregate, I think those add up to between 35 and 58 months, so essentially three-to-five years from the point of triggering to get a project online.

And so that is an important quality of this option. We need to be looking at least three-to-five years forward with our analytic tools trying to understand whether we have a potential problem that emerges out there, because if it takes three-to-five years to implement the chosen solution, you need to be essentially not just monitoring today what's happening, but projecting what's going to happen that far forward or even further.

So here's our pool of projects. Three of them, Carlsbad Unit 6 in San Diego, Huntington Beach Phase 2 in Orange County and Alamitos Phase 2 in West L.A. Basin. There was a fourth project that was nearing the point of getting an Energy Commission license and a South Coast AQMD permit, but it has withdrawn and it's no longer under consideration.

So what are the next steps for this option? Or these options, excuse me, these options? The OTC deferral option is really ready to be implemented. The generation construction option has some detailed questions about the longevity of permits -- as time goes by, what kind of steps would be necessary to refresh a permit or update or if too much time has gone by to start all over?

We need to continue our efforts. Maybe continue is a better word than initiate to resolve these remaining issues with the air districts. Their presentations developed for today can be helpful and we can continue the dialogue with them.

As the staff paper on this subject indicates, there are still some questions on the financial side of how these options work. For the OTC deferral option we're at short term. Nothing's being built, just being operated longer. Who pays? Is it an ISO AERMOD contract? Is it some kind of a PPA that the PUC approves?

How do -- and that may depend on agreements about how a plant is even operated. Is it operated solely in a reliability mode? Does it generate any energy, is it only dispatched when reliability dictates or is there an energy component also -- some complications of how to treat that.

From the new generation construction option, clearly that's a plant that's going to be built for the long term and a PPA is the appropriate vehicle for that.

So my last section is going to be how to use the LCAAT tool or other information, like ISO power flow studies to inform the triggering process.

So in some respects, we've already been through a dry run to this a year ago. LCAAT showed that there were future deficits in year 2021 in the L.A. Basin. ISO had not conducted studies that showed that. They did agree to conduct those studies. The studies confirmed that there was a problem, but instead of triggering any action at that time, we were basically in a watch and wait mode, because the timeline to address those problems seemed to be far enough away that we could afford that time.

Now a year has passed. LCAAT still is showing 2021 problems. ISO is already committed to study 2021. It may be time to act in the not too distant future, if we have ISO studies that confirm what LCAAT showed and what the ISO studies showed a year ago.

So when we have that kind of information, either from LCAAT or from ISO, how do we use it? This is sort of a stylized pair of charts side-by-side to help you see that.

On the left hand panel, the blue line, which is sort of in the middle, is the original we call them sort of the gross LCR requirement. The green line, below it, is the adjusted LCR requirements. And those adjustments come about because of demand-side measures and/or transmission projects that weren't counted on in the initial gross LCR requirements.

Then there are two jagged lines, one purple, one red. Those are showing resource tabulations in the same area. And whenever the resource tabulation, either purple or red goes below the green line, that's when there's a deficit.

So turning to the right hand panel, case A, the purple line, shows that it dips below the green line in one single year, in this case 2021. And then bounces back up and then hovers above the green line. That would be the kind of information that would lead us to conclude that we only needed a temporary solution to a problem. So an OTC deferral request might be an appropriate option to consider.

Alternatively, in case B, the projections show a worse gap and also one that never resolves itself in a positive surplus. And so this is the kind of information that would lead us to decide that a new generation option was appropriate.

I think this slide pretty much says in words on paper what I have just said. But the elapsed time point in the -- the last two sub bullets -- let me focus on those. The elapsed time from triggering until a solution can be operational is important. Going back to the 2021 issue in West L.A., if the problem is OTC is a delay, like Mesa Loop-In, and it is a question of being delayed a year or so but we are four or five years away from that issue or that happening, then there's no point in getting alarmed or triggering anything at this point. So this wait and see notion that I mentioned earlier, it seems appropriate.

In addition, it may also be the case that you decide you want to trigger something now, but you're still -- because of the elapsed -- because the solution takes a long time to implement, like the new generation option.

If new information comes along in the meantime while that process is playing itself out, then you want to know that there are off ramps that can be triggered if new information emerges. So if the next cycle of analysis comes to a different conclusion, you want to be able to essentially cancel that option before you've spent too much money and you're irrevocably committed to building a new facility.

So let me wind up with a couple of slides dealing with the particular circumstance of Carlsbad in the San Diego subarea. This is the bar chart showing the same information that Ms. Wong presented in the red bar. So we're showing the surplus or deficit in the San Diego subarea from 2016 through 2021. The red bars are the same information that she showed in a line graph format. The blue bars are what would happen if Carlsbad was delayed one year. So instead of being operational in the summer of

2018, it's operational in the summer of 2019.

So Encina has closed down at the end of 2017. There's no Carlsbad in the summer of 2018. There's a huge deficit. Next summer comes along, Carlsbad has become operational. In the meantime, there's a small deficit. This is the obvious circumstance for an Encina OTC deferral. It's a short-term period. We know what the solution is. It's Carlsbad. The circumstance would be quite negative if we were to try to just ignore it. And so OTC deferral seems like the appropriate action in this circumstance.

So where are we? Carlsbad now is sufficiently delayed that the agencies need to strongly consider making a deferral request. The issues are really how much Encina capacity to defer and for how long? They also need to be more serious about deferral of Redondo Beach or Alamitos, due to Mesa Loop-In. We'll know more this fall about the delays in a final decision, if any. And then whether or not those approval delays can be made up in the project timeline itself.

ISO's agreed to provide study results later this year. And SACCWIS will of course need to consider an Encina deferral possibly in two steps, becoming familiar with the issues this fall and then as soon as the information from the ISO about the nature of the solution becomes available, then initiating a formal action by submitting a formal report to the Water Board.

And that's all I have for you this afternoon.

MS. RAITT: Thank you, Mike.

Next is Bhaskar Chandan from the South Coast Air Quality Management District.

MR. CHANDAN: Good afternoon. First of all, I'd like to thank CEC for inviting South Coast to be a part of this workshop. My name is Bhaskar Chandan. I am a Supervisor with the Power Plant Permitting Group at the South Coast AQMD. And today, I'm going to present some of the steps involved in permitting a power plant for the South Coast.

As you know, South Coast is the Air Quality District for Southern California. We have a population of around 16 million people, our area covering about 11,000 square miles. We regulate about 27,000 facilities out of which about 400 are major sources. And unfortunately, we also have the worst air quality in the U.S. for ozone and PM 2.5.

The Title V Permitting Program was a part of the National Operating Permit Program established under Title V of the 1990 Clean Air Act. It provides a consistent permitting process for major stationary sources nationwide.

And it consolidates requirements of all the permits into one document. Previous to Title V we used to have what we call command and control permits. After Title V we have consolidated all those permits into one document.

Additionally, it also increases compliance accountability by the facility operator. We are required to add a lot of conditions and requirements to account for compliance issues.

And a corner stone of the Title V Permitting Program is the public participation and EPA review of the permits. And most of the power plant permits that we do, does involve public participation.

So who's subject to Title V permits? Predominantly all the power plants that we permit are subject to Title V. But up there you can see the thresholds that we have for the Title V Permitting Program, which would constitute major sources.

For the NOx and VOC, we are at ten tons per year as our thresholds. Those are one of the lowest thresholds in the nation.

In addition to meeting those thresholds there are other facilities who might get pulled into Title V Permitting Program. Those would be the facilities who are subject to the Acid Rain Program, Title V of the Clean Air Act, which would include all the power plants. Any facilities that are subject to NSPS and NESHAP, those would also be pulled into the Title V Permitting Program.

So the general power plant permitting process, it includes for the South Coast AQMD -- we are the air permitting authority all power plants within the South Coast Air Basin. For the projects that involve CEC, that are regulated by CEC, we are co-air permitting authority on those projects. And these are primarily power plants that are over 50 megawatts.

On major projects, the lead agency for preparing the environmental impact analysis for power plants small than 50 megawatts, usually it is the city or the county. And for power plants that are over 50 megawatts, CEC does CEQA plan or the CEQA process.

Permitting and licensing process is pretty much what was there in the previous slide -- AQMD's role and CEC's role in permitting a power plant. So SCAQMD, the determination of a compliance and permitting process, in order for AQMD to grant a determination of compliance or a permit, the project must meet specific requirements.

Primarily on top of the list are the NRS requirements where we look at the best available control technology or lowest achievable emission rate, BACT/LAER. We look at the air quality modeling and we look at emission offsets. Any increased in emission need to be offset and we need to make there are sufficient offsets before we issue the permits.

We also do a new source review for toxics emissions where we evaluate cancer risks and non-cancer risk. This involves running dispersion modeling and coming up with a health risk assessment on the project.

For power plants and for other major projects sometimes PSD is triggered for power plants. For attainment air pollutants we are required to look at PSD aggregations. The analysis is similar to our new source review where we have to do BACT analysis, air quality modeling. But for PSD in addition, we have to do a visibility modeling analysis.

For all the power plant projects we also have to look at greenhouse gas emissions and PSD for greenhouse gas. And we have to a BACT analysis. And that's been taking up -- on the recent projects it's quite a lot of work that we are doing to establish a top down BACT analysis for these projects.

And all the Title V permits, these need to be noticed and receive public comments. It goes to EPA, any comments that we get from the public and the EPA, we need to respond to those before we can issue the permits.

This is a simplified flow chart basically, of CEC's licensing process on the top and the South Coast AQMD permitting process at the bottom. Basically this is to depict where the two agencies are interrelated, interconnected. Once we issue the PDOC, the Preliminary Determination of Compliance for the proposed power project that triggers the PSA on CEC's part.

Further down once we issue the PDOC we receive comments, we address those comments, and we make changes as required to the permit before issuing the FDOC.

Once the FDOC is issued, CEC issues the FSA. And we typically don't issue the permit to construct at that point and time. We wait for the CEC to issue the final license before we issue the permit to construct for a Title V RPSD facility.

The time lag between the FDOC to issuing a permit could be a few months or longer. That depends on how long CEC takes to issue the final license and other issues that could arise.

At AQMD this is a typical permitting process where once we get a complication we make sure that all the information is there for us to make an engineering evaluation. We do quite a bit of leg work in doing an engineering evaluation where we study the BACT air quality modeling, offsets, health risk assessment. We basically look at our rules, we look at the state rules, we look at the federal rules.

And just to give you an idea, one of the recent projects where we had done an engineering analysis, it was close to 300 pages long. So it's a lot of work on our end to issue these permits.

Once we issue the PDOC, of course, there is public notice involved and we have to review and consider all the comments before issuing the final permit.

These are some of the recent permitting projects that we have done. I think Matt and Mike both have gone through most of these projects, so I'll go through it pretty quick.

On the top are the project permits that we have issued: LADWP Scattergood Repower, we issued this permit for 524 megawatts. This was a few years back, actually last year, and the plant is started. We have received just recently more permits for repowering Boilers 1 and 2 from Scattergood for a total of 345 megawatts. Those are in the initial stages.

City of Pasadena DWP Repower Project, we had issued this permit in 2013, it's a 71 megawatt. It's currently undergoing commissioning and it's expected to start by December of this year.

Pending permits: El Segundo Repower, we already heard this has been withdrawn and terminated. The applications in the South Coast are still active, we have to do some administrative work before we cancel those permits or applications.

AES Huntington Beach Repower Project, which is very active right now, it's 844 megawatts. You already heard about this.

Both AES Huntington Beach and AES Alamitos Repower, these have gone through the public noticing. We have received a lot of comments and we are in the process of responding to those comments. And we expect to issue the FDOCs shortly for both of those projects.

Assessing emission offset needs, facilities who are permitting power plants with the South Coast AQMD, they have an option of procuring the credits in the open market or for boiler repower projects they can ask AQMD and use the internal bank.

We set up the Rule 1304.1, which was adopted in September 2013. It provides power producers at existing locations the option to pay a fee to use offset from the AQMD for repowering utility boilers. There are two options: either it can be paid annually or they can make a full payment up front.

And there are nine anticipated repowering projects that we currently have, potentially over 5,700 megawatts of power replacement is what we are anticipating.

In addition to the 1304.1 Rule we are also developing a couple of other rules: 1304.2 and 1304.3. I believe these were covered in last year's workshop at UC Irvine in quite a lot of detail. The timeline has slipped a little bit, we are hoping to adopt it this year, but it slipped to early next year.

And these two rules basically, the first one is for projects that are being regulated by CPUC and the second rule is for local public owned electric generating facilities. So we are making the offsets available to them, because we know it's difficult to get some of those offsets in the open market. So similar to the 1304.1 we are in the process of adopting these two rules for other sources that cannot avail the 1304.1 offsets.

And that concludes my presentation. There is my contact information and my manager's contact information, which is up there. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

MS. RAITT: So our next presenter is presenting remotely from WebEx. And it's Jim Swaney from the San Diego Air Pollution Control District.

Go ahead, Jim.

MR. SWANEY: Okay. Good afternoon. I'm Jim Swaney. I'm the Chief of Engineering with the San Diego Air Pollution Control District. I do apologize for not being able to attend the workshop in person with the rest of you, but I do appreciate the Energy Commission having this service available, so I still can present.

So let's go on to the next slide please. What I was going to talk about today is a little more specifically on the shelf life of permits and what can be done to extend the approval. And then in support of the new generation option approach, what impact this would have on Carlsbad Energy Unit #6. So next slide please.

First, I wanted to go over our normal approval process. Now much like Bhaskar just went over for South Coast, we have a very similar process. So I'm going to just hit the highlights here.

For any application, of course, we have to show that it's going to comply with all of the applicable regulations at the local level, and that's again just like South Coast, new source review is going to be the primary rule that we have to show compliance with. But then there's also some state and other federal requirements.

We would normally issue an Authority To Construct that would include the conditions that they need to construct with to show compliance. And they have to be in compliance with that. Next slide please.

Once the unit or equipment is constructed, the Authority To Construct becomes a temporary operating permit until we can go out and inspect the equipment. Once we've inspected it and everything looks good, then a Startup Authorization is issued, which allows them to move on to the commissioning and testing phase. Once everything has been demonstrated to be in compliance then we would issue the Permit To Operate. Now of course, power plants use a slightly different process, so next slide please.

Our local Rule 20.5 governs how we handle power plants that are subject to the Energy Commission licensing. The application to the Energy Commission is considered the same as an application to us for an Authority to Construct. Like South Coast does, we issue a Preliminary Determination of Compliance and then a Final Determination of Compliance. And that Final Determination of Compliance has all the conditions necessary to ensure compliance. So next slide please.

Now the Final Determination of Compliance acquires all the rights and privileges of an ATC, once the Energy Commission approves the AFC with a certificate containing all of the conditions listed in the FDOC. And then we consider the AFC approval date as the date the ATC is granted by the district. So next up, we will talk about the shelf life and so the next slide please.

Now initially, the ATCs are issued to allow one year for construction to be completed, however it might be a longer period if needed for a construction. There is a time limit. It's in our local Rule 17 that the ATC including any extensions granted to that is valid for a maximum of five years. If for whatever reason it would take longer than five years to construct the operation, at that point then we would have to have a new application and reevaluate it from scratch, if you will.

Now, a company can apply to extend the life of an ATC again up to that maximum of five years. But we would be reevaluating the equipment to assure continued compliance with any regulations before we could grant any extension. Next slide please.

So when that extension is requested, we will reevaluate things under new source review and different things such as best available control technology, lowest achievable emission rate, the air quality impact assessment, health risk assessment and other regulations that the local, federal and state may have. Going a little bit more into specifics, the next slide please.

Under BACT or LAER, this is a moving target. It can be affected by decisions that we make, permitting decisions that other districts make, additionally decisions can be made in other states and by the federal Environmental Protection Agency. Of course, for power plants BACT has been pretty much established for a number of years. I don't see that being an issue going forward.

Next slide please.

So the next thing the Ambient Air Quality Impact Analysis, we would need to redo this modeling of the emissions if there were a new standard came into play from EPA or if EPA revised the modeling guidance. Or if there any updates to the model that we use, which is AERMOD. Any of those cases, we would need to re-run an AQIA. If not, we would not need to do that. Next slide please.

Similar with the health risk assessment and this looks at the air toxic emissions, if there is a change to the modeling guidance or the health risk values, at that point then we would want to reevaluate the health risk assessment before granting an extension of the ATC. Next slide please.

Now other district prohibitory rules, because they apply across the board, new, existing it doesn't matter, it most likely would not impact an extension request for an ATC.

Looking then at some federal rules, if there were any new regulations coming out under new source performance standards, maximum achievable control technology, MACT standards, things like that, we would need to evaluate the equipment to make sure that they were still in compliance with those regulations. And then next slide please.

Another federal regulation, of course, is

Prevention of Significant Deterioration or PSD. In San Diego, there are two types of PSD. There's our local PSD rule, Rule 20.3. And then there's federal PSD, which currently in San Diego is implemented by EPA. We cannot implement federal PSD unless we either had a rule approved by EPA or received delegation from EPA, neither of which has happened to date. Next slide please.

So under federal PSD, of course, if you're subject to it, you have to get the approval from EPA as well as getting the Energy Commission license and the FDOC from the District.

Now in the past, we have received -- requested and received kind of case-by-case PSD delegation for some projects. We don't see that going forward. EPA has strongly expressed their opinion they would like us to develop our own rule to take over PSD. And so we are expecting to have an EPA-approved PSD ruled in the 2017-2018 timeframe. Next slide please.

Now, our local PSD rule is consistent mainly with what the federal PSD was in 1995. Under a specific Senate Bill, 288, it can be difficult to get rid of certain, I'll call them legacy rules. So this rule will continue to be enforced by the District and is incorporated into the ATC with the same period of validity, no more than five years. Next slide please.

Now, specifically on to Carlsbad Energy Center, or course as everyone is aware they received certification for 600 megawatts, six LMS100 turbines, but only got the Power Purchase Agreement for 500 megawatts or five of those turbines.

The District FDOC, as the ATC, was granted for a two-year period, knowing that it would take longer to construct, for up to the six turbines. However many turbines are under the Power Purchase Agreement doesn't matter from our standpoint. And this ATC -- the current ATC expires June 30th of 2017 and can be extended until at the most June 30th of 2020. Now, next slide please.

And so whether the Applicant elects to build only five turbines and a sixth turbine later or all six turbines now makes no difference to us. At any time that they do apply for an extension, which if they're delayed, they might have to do it for the whole project now. But at that point and time, we would determine if there was any need to reevaluate the approval before granting the extension.

Now one thing I do want to mention on this, probably the biggest thing that has happened since the FDOC was published is the revised OWEHA Health Risk Assessment Guidelines. We actually looked at those, prior to issuing the FDOC, didn't think at the time that it would have any impact on the approvability of the project, so we would need to just update that little look in once we get an application to extend the ATC for Unit #6. So the last slide please.

I wanted to get my contact information in case anybody has any questions specifically about San Diego rules. And I'm open for any comments or any questions. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

I was going to thank the panel. I found that there were fairly thorough and clear presentations. Do we have any questions from the dais?

MR. DOUGHTY: Chair, I also wanted also offer an appreciation to Mike, Lana and others who worked on the LCAAT tool. It's been a tremendous indicator for us, a good first look at possible problems, and in effect a trigger to explore more deeply surpluses and deficits. So thanks for that.

We heard a lot about the opportunities ahead on both OTC extensions and other mitigation measures. And I guess I would just, rather than rehash what I heard from these panelists, commit the ISO and our staff to getting after these and tackling the action plans that we need to undertake both at the Water Board and in other forums.

So finally, Chair, you mentioned as we kicked off the challenge of the timing, permitting timing. And that's another area where we're going to need to allocate some collective energy among the agencies to try to shorten that and comply with the Governor's objectives.

CHAIRMAN WEISENMILLER: Precisely.

MR. BISHOP: I appreciate getting the update and the Water Boards are prepared to work SACCWIS on what looks like the need for an Encina extension.

I am a little concerned about the issues around the Mesa Loop. It seems to me that it's not well defined what the problem is and what the solution is. I'd like to make sure we work with the CPUC to figure out if there's any way to get the environmental review done in a timeframe that wouldn't require us to go through an extension on one of the OTC plants for that.

But we'll have to work through the next few months to see about that.

CHAIRMAN WEISENMILLER: Well, yeah we do. And President Picker's trying to expedite the permitting and licensing to get this GO-Biz process review effort going and PUC transmission. I certainly encourage anyone with ideas to contact GO-Biz on how to help there.

Let's go to public comment. I think in the room we've got, let's start with Steven Kelly.

MR. KELLY: Good afternoon, Chairman. I'm Steven Kelly, Policy Director for Independent Energy Producers

Association.

And I found this a very helpful workshop so far today. And I want to feed off some of the things that Mike Jaske presented in his framework going forward, and then talk about some timing issues. Because I agree with Mike that there's a huge amount of uncertainties that we're facing now and it makes it very difficult to know exactly what to do and when to do it.

I'll have a slightly different opinion about whether it's either/or on some of the options. I think there may be a dual path forward. And specifically, I think considering a path forward that has a competitive all source solicitation up front to determine the full range of resources that might be available to meet the needs in a timely manner.

And then specifying a date certain for a permit to be in place and a date certain for when construction is supposed to be completed, so the facilities or the resources are available to meet the need in 2021 would be critical in doing that, I think to clarify. Otherwise, I think we potentially run the risk of the tremendous amount of litigation that has occurred over the last couple of years, when we avoid that pathway.

I just want to point out we're buying capacity insurance basically here in a world that's heavily vetted with unknown conditions. And that's what you're doing. You're just buying capacity to make sure that you've got the resources in place to serve the needs. And I don't know if we're ever going to get to the point where we can time this perfectly. So I recommend moving forward.

And I just want to point out some of the timing considerations though that are a problem or important to be aware of. If the need is in 2021, that probably means that you need a fully deliverable resource by 2020 at the latest. If you need to have construction and time that into the process, you probably need to figure one-to-three years depending on the resource type to do construction.

Nobody's going to construct until you have the RFO. That usually takes 18 to 24 months, maybe a little longer. When you back all that out, you're into the 2017 timeframe pretty quickly.

Unfortunately, we're now in a planning process in the IRP where that looks to be going to take at least two years. That's not going to really get going until the 2017. It's looks like it'll probably trickle into 2018. With a final decision at the end of 2018 usually, which means you don't have a final procurement 2019.

There's a potential disconnect there and I just want to bring it to your attention that if this is an important issue, we should engage to identify it and then move quickly for the solicitation process to fix the problem.

So overall, we need market signals. The marketplace needs that. It's incredibly important. I recommend an all source solicitation as soon as possible, hopefully in 2016, maybe 2017 at the latest, in order to meet this schedule. Make sure that your permit is an obligation, construction and viability is an obligation in that.

And then to the extent that that doesn't work, I think you may still have time to deal with the OTC deferral as a backstop mechanism. And I would fully expect OTC parties to be bidding into these solicitations as well.

CHAIRMAN WEISENMILLER: Thanks, Steven.

Greg Blue?

MR. BLUE: Good afternoon. My name is Greg Blue. I want to thank everybody who's stayed and still here to hear all the comments. I'm Vice President of Asset Management for Cogentrix. And Cogentrix has a fleet of six fast-starting flexible peakers located in California. The ones that are really germane to this discussion, we have two located in the San Diego subarea. One located right on the border right across the street from Otay Mesa and Pico Pio and one up in Escondido.

Both of these projects are not contracted for

2017. And that's part of the big problem that we're having here is that you have these peaker plants which are currently, currently keeping the lights on. And you can ask the ISO about this. These peakers down there are five-minute start time, one-minute minimum run time. We're offering four starts a day. And the ISO is often calling us five times a day in the last couple of months.

So but the problem is we're not a renewable. We're not a preferred resource. We're not a CHP. We're kind of like out there. And we're struggling to find how we can find some medium-term contracts. We're not even looking for long-term contracts. We're struggling and having to scratch for resource adequacy contracts that are three months, six months. Maybe if you're lucky, you get a year contract.

And that's really not a way -- following up on Steven's comments, we are the insurance policy that you're going to need for the next five years. You have all these delays happening on the resources, on the transmission, on the IRP, the timing of all that. And so I just want to recommend that as you're looking at options going forward, right now we're focusing on the two options: the once-through cooling deferral and the pool of plants. We want to recommend that you put in a third option of contracting with existing merchant generation.

And I think that that's -- and we're really looking for five-year contracts. We're not looking for long-term contracts. So I think that's an important consideration. We'll be filing written comments with much more detail on this. But as I said before, we're there now. Like two weeks ago, we were called in the morning and twice in the evening.

And if you look at the amount of renewables as they come online, our number of starts have also sequentially gone up just on the same pattern as that. So it's clear to us that we're needed.

And by the way it's also clear, CalPERS is an investor in our projects. And in their CalPERS for California 2015 Report, which was issued earlier this year, they noted that these peaker plants are the types of plants that are needed for going forward to transition to the long-term future that we're all going get to.

So I think even CalPERS has recognizing this, but we hope that we can see some action from some of the other regulators. We really need to see some contracts coming, longer-term contracts. I don't know where we're going to get it. We're going to recommend it here. We're going to work at the IRP. We're going to work with the PUC. We're going to keep working with the ISO on all of this.

But just it's an important issue for us. Thank you.

CHAIRMAN WEISENMILLER: Okay. Thank you. In your written comments it would be good to get some information on the operating statistics?

MR. BLUE: Yes.

CHAIRMAN WEISENMILLER: Thanks.

MR. BLUE: That will be in our comments.

CHAIRMAN WEISENMILLER: Okay, great.

MR. BLUE: For sure.

CHAIRMAN WEISENMILLER: Anyone else in the room, anyone on the line?

(No audible response.)

MS. RAITT: No, I don't think we have anyone on WebEx, but we can check the phone lines. Please mute your line unless you want to make comments. And if you're on the phone, we'll just open the lines briefly.

(No audible response.)

No. I don't think so.

CHAIRMAN WEISENMILLER: Okay, so let's transition from public comment. On the dais, any final thoughts, Tom, Mike?

MR. DOUGHTY: Well Chair and colleagues. This was a great discussion today. And as I mentioned when I offered my opening remarks, I've sat in on literally tens or dozens of preparatory calls over the last months, getting ready for this moment where we're announcing this challenge that we've assessed and now verified. It's time now to kind of move to a ton of action and get after these. So we've gone over where we need to be and what we need to do. And we're eager to get cracking on the action plans to mitigate these challenges.

To Mr. Blue's comments, thank you, Greg. We've heard that from other generators as well and we take these comments to heart. There is a significant effort that has to be undertaken to provide those longer-term contracts that you're requesting, but we do hear you and we hear the other generators as well.

Chair, I think that's all I've got in my notes. Thank you again for a good discussion. Thank you to our panelists.

COMMISSIONER FLORIO: Yes. I think the main takeaways I have thus far are that we really do need to start moving on the Encina extension of the OTC. The contract was approved but the appeals are holding it up and it looks like we're going to need at least the 90 days if not more. So I think it's time to get that process started.

I think the situation in L.A. is more unclear to me. As I look at the sensitivities that use the 2015 IEPR Forecast it seems like we've got a 1,000 megawatt cushion in L.A. and probably 500 megawatts in San Diego. But there are these other cases that look much more dire, so I guess the question is how much confidence do we have in that forecast?

It might be helpful to look at the 2015 IEPR high-demand case and see where that falls within this range. I assume it's less than the 2013, but more than the 2015 base forecast. And that might give us some indication.

As far as the Mesa Loop-In potential delay, as Chair Weisenmiller sais, we're hopeful there won't be a delay, but if there is we may need to start looking at some potential mitigation action there as well. But hopefully we'll get that decision out by the end of this year and everything will be on track. So we'll see how it goes.

MR. TISOPULOS: Yeah. I found the workshop extremely informative. And I'm glad we are here. But it looks like we may be running out of time with some of the signals that we are getting out there. There are some potential solutions.

We have really zero time for error here. So we have -- all agencies have to coordinate their activities and if there is a need to further discuss the feasibility of some of the scenarios or options at the table, we are going to be there to be true partners and see how we can work best together. Certainly we need to harmonize and coordinate our activities here.

MR. BISHOP: Yeah, I made my comments before public comments. So thank you.

CHAIRMAN WEISENMILLER: Great. Well, again, I want to thank all the other agencies for their participation today. This has been a real team work effort. Certainly, I want to thank the staffs for their hard working analysis and for organizing the workshop. Thank you to anyone who has participated in it. I look forward to your public comments on September 12th.

And I think obviously one of the things, which we all need to do some thinking about is we're looking -- as I said we're sort of marching through what we had in the SONGS plant, some of which (indiscernible) Sycamore-Penasquitos we launched -- actually before SONGS was announced it was just gone, you know, as sort of a contingency measure.

So again trying to get those over the finish line, but also I think all of us need to think some about how this interacts with Aliso. And you know I mean we have our sort of silos of crisis and somehow in the real world they do interact. And so that's one of the things going forward. We need to do some consideration of those interactions.

So anyway, again thanks everyone for being here. And this meeting is adjourned.

(Whereupon, at 4:07 p.m., the workshop was adjourned)

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REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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IN WITNESS WHEREOF, I have hereunto set my hand this 6th day of April, 2016.

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