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CALIFORNIA INDEPENDENT SYSTEM OPERATOR

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	JOINT AGENCY WORKSHOP
2017 Integrated Energy Policy Report (2017 IEPR)	RE: Distributed Energy Resources

JOINT AGENCY WORKSHOP ON APPLICATION OF
DISTRIBUTED ENERGY RESOURCES ON THE CALIFORNIA GRID

CALIFORNIA ENERGY COMMISSION

THE WARREN-ALQUIST STATE ENERGY BUILDING
ART ROSENFELD HEARING ROOM - FIRST FLOOR
1516 NINTH STREET
SACRAMENTO, CALIFORNIA 95814

THURSDAY, JUNE 29, 2017

10:00 A.M.

Reported By:
Peter Petty

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Simon Baker, California Public Utilities Commission

STAFF:

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PANEL PRESENTERS (* Via telephone and/or WebEx)

Panel Discussion - Agenda Item No. 3:

Mike Gravely, California Energy Commission
(Panel Moderator)
Rachel McMahon, California Public Utilities Commission
Delphine Hou, California Independent System Operator
Noel Crisostomo, California Energy Commission

Panel Discussion - Agenda Item No. 4:

Mike Gravely, Energy Commission
(Panel Moderator)
Simon Baker, California Public Utilities Commission
Gabe Petlin, California Public Utilities Commission

Panel Discussion - Agenda Item No. 5:

Tom Flynn, California Energy Commission
(Panel Moderator)
Delphine Hou, California ISO
Mark Esguerra, Pacific Gas & and Electric
Jeff Billinton, California ISO

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PANEL PRESENTERS (* Via telephone and/or WebEx)

Panel Discussion - Agenda Item No. 6:

John Mathias, California Energy Commission
(Panel Moderator)
Jonathan Changus, Northern California Power Agency
Chris Beltran, Imperial Irrigation District
James Barner, Los Angeles Department of Water and Power
Jason Rondou, Los Angeles Department of Water and Power

Panel Discussion - Agenda Item No. 7:

Matthew Tisdale, More Than Smart
(Panel Moderator)
Mark Esguerra, PG&E
Damon Franz, Tesla
Jim Baak, Vote Solar
Carmen Garralaga, SMA America

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P R O C E E D I N G S

June 29, 2017 10:01 a.m.

CHAIRMAN WEISENMILLER: Heather, do you want to go through our administrative announcements?

MS. RAITT: Yes.

Good morning, so welcome to today's IEPR workshop. It's a joint agency workshop on the Application of Distributed Energy Resources in the California Grid. I'm Heather Raitt. I'm the Manager for the IEPR.

And a few housekeeping items, 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. We are being recorded through our WebEx conferencing system, so there will be an audio recording posted on our website in about a week. And a written transcript will be available in about a month.

At the end of the day, we will have an opportunity for public comments and we're going to limit that to three minutes per person. You can go ahead and fill out a blue card, which is at the front. And give it to me and you can give your comments at the end of the day. For folks on WebEx, there's an opportunity for comments also at the end of the day. Just raise your hand to let our coordinator know you'd like to comment.

All the materials for this meeting are available at the entrance and posted on the website. Written comments are welcome and due on July 13th and the notice has all the information for submitting comments.

So with that, I'll turn over to the Chair. Thank you.

CHAIRMAN WEISENMILLER: Thanks, Heather.

I'd like to thank everyone for being here. Today's topic is we're talking about distributed energy resources on the Grid. And I would point everyone back to an en banc that President Picker and I had a couple of months ago on sort of the changes in the California market, which is not just the rapid growth of CCAs, but also everything that's going on behind the meter.

And you have fundamentally both the market structure and the technology are changing fast and really changing the nature of the utility obligations. Changing and transforming the nature of our Grid and providing both a lot of opportunities and challenges. And so we wanted to focus on today's workshop, obviously my colleagues here from both the ISO and the PUC, to really help look at these issues since it really cuts across all three of us.

And again I think this workshop sort of again emphasizes that we're working in pretty tight harmony on this. And we're trying to make sure that everyone, say Michael put out the roadmap at the PUC, that we're really using that as the basis for our research funding priorities. And at the same time, obviously the CAISO's taking its historic effort on consulting procurement and the wholesale market distributed energy resources.

Keith, do you want to say a few words?

MR. CASEY: Yeah. Well first off, thank you Chair Weisenmiller, for including us in the workshop today and on the dais today. The ISO is very, very committed to integrating distributed energy resources into our wholesale markets and into our planning process as well.

Obviously, these resources present some unique challenges. And I know we have a lot of efforts underway, both on the market design side to understand those unique characteristics and make sure we evolve our markets and reduce barriers to enabling these resources to participate in our markets. And certainly operationally and in the planning side, again there are some unique challenges with incorporating distributed energy resources into our transmission operations as well as our transmission planning and I look forward to this afternoon's panel on some of the innovative approaches we're taking to enable that.

So generally, I look forward to the discussion today and appreciate the opportunity.

MR. BAKER: Thank you. Good morning. I'm Simon

Baker. I'm the Deputy Director of the Energy Division for the PUC and standing in here for our Commissioners. Regrettably, today is our Commission meeting, so they were not able to be here today.

But I do want to say that I'm pleased to be here. And as I've said before, the PUC and CEC and the ISO have been collaborating extensively and I expect we will continue to do so. So I'm looking forward to today's workshop and hearing from the presenters and also the participation of everyone.

We've made a lot of accomplishments, but there's yet a lot more to do. So hopefully we can kind of uncover what are some of the key fronts of activity moving forward in today's workshop.

CHAIRMAN WEISENMILLER: Yeah, Martha. Do you have anything for the intro to say?

MS. BROOK: Good morning. I'm Martha Brook. I'm Advisor to Commissioner Andrew McAllister, who would love to be here today, but he has official business elsewhere.

Andrew's been very active in demand response in particular and integrating demand side resources into building code, for example. And he's also been very active in previous IEPR reports. And so my job today is basically to try and figure out whether the recommendations we made five years ago in this area have been resolved or we've made progress on and which would be our current recommendations in this IEPR. So I'll be looking forward to today's discussions.

Yeah, so we are also having a follow-up workshop on demand response in particular, on July 26th. And both myself and Bryan Early, who is Commissioner McAllister's First Advisor, will be reaching out to some of you hopefully, for your participation in that workshop. And again that is going to be specifically on demand-response and looking to make recommendations in this year's Integrated Energy Policy Report.

So we hope you can participate. Thanks.

CHAIRMAN WEISENMILLER: Mike, do you want to start?

MS. RAITT: Great, so our first panel is an update on the status of the state-level roadmaps. And Mike Gravely from the Energy Commission is the Moderator.

MR. GRAVELY: Thank you. I'm Mike Gravely from the Energy Commission R&D Division.

And in preparation for this workshop, one of the things we did on the 13th, was we held a staff workshop to review the active roadmaps that currently exist. These roadmaps were developed by the three agencies: the ISO, the PUC and CEC. And we have three of those that cover a large portion of the DER energy storage, energy efficiency, demand response and vehicle-to-grid integration.

So these roadmaps were published in the 2013-2014 timeframe. So one of the questions we were asked was are the roadmaps -- what's been done as part of the roadmap? Where are we? Where are we going in the future? And should there be any changes or updates to the roadmap, or is the roadmap as is pressing forward doing what we want it to do? So we will present the three of those in just a minute.

There is a fourth workshop that we're doing later next month for a roadmap. There is a roadmap on microgrids. Microgrids are one of the tools to integrate Advanced DER. We have had four previous workshops in preparation for this. We will be developing a roadmap and the draft will be available within the September timeframe. We have another workshop next month to go through the logistics with industry and stakeholders on that roadmap. Again, that's a roadmap that's being developed by the three agencies.

And with that, I'll turn it over to Rachel, who will talk about the Energy Storage Roadmap. You can be here or here, your choice. I'll just set up your slides for you.

MS. MCMAHON: So good morning, my name is Rachel McMahon. And I'm very loud this moment. And I'm a Senior

Analyst in the California Public Utility Commission's Energy Division focused on energy storage.

So the following presentation is a somewhat truncated version of the presentation that we gave on June 13th, which I will go through quickly. Next slide.

So this slide illustrates, which of course you're already familiar with, is that the Energy Storage Roadmap is organized around three principals and into five priority tracks. Others being planning, procurement rate, treatment, interconnection and market participation. Next slide.

Okay. So we started by presenting the initiative that each agency has whether stakeholder processes, rulemakings, research, etcetera, that support the specific items in the roadmap. So those are listed here. So starting on the left the CAISO has the Energy Storage and Distributed Energy Resources Initiative. It's already complete Phase 1, it's about to wrap up Phase 2 and will likely have a Phase 3; the Expanded Metering and Advanced Telemetry Initiative; storage interconnection and metering rule's enhancement.

For the CPUC, in the middle column, the Electric Storage Rulemaking; the Integrated Distributed Energy Resources Proceeding; the Distributed Resource Plan Proceeding; Interconnection Proceeding and Smart Inverter

Working Group; DER Action Plan -- which there'll be a presentation about later today, which is not a proceeding, but a guiding, planning document that is used across distributed energy resource energy proceedings -- and Resource Adequacy.

And then of course on the right, this agency, the Energy Commission has supported storage, storage policy development through EPIC research and grants; participation in proceedings and working groups and development of the StorageVET tool. Next slide please.

Oh, and what I should say actually before we dive into the actual elements in the roadmap is that this list is not exhaustive, so there's efforts happening at all agencies that impact energy storage. As so for example, you know, the Integrated Resource Planning Proceeding, New Transmission Planning Process, etcetera. Those all relate to storage as they relate to energy resources generally.

So following are the slides that we presented. As starting with planning each agency went through its activities. The color-coding on the far left indicates the priority on the roadmaps, so red for really important, orange for of medium importance and yellow for lower importance.

So this slide and the activities in the roadmap focus largely on distribution and transition grid needs and services and the ability of storage to fulfill those. Next slide.

And the four action items for procurement that were in the Energy Storage Roadmap are listed here. They are focused on both valuation of storage and resource adequacy rules. The roadmap, I will note was created before procurement actually began under the Storage Roadmap, so I'm curious whether some of these items might change. Next slide.

Rate treatment, so the action items in this section focus on station power, net energy metering and what we are calling multiple-use application. There's some overlap here. Prior sections in the final two items which are focused on distribution level needs and procurement. Next slide.

So not surprisingly, there was a lot of focus in the Energy Storage Roadmap on enter connections. The next three slides go through that. These items have been handled primarily through the CPUC's Interconnection Proceeding and the CAISO's Expanded Metering And Advanced Telemetry Initiative. There are also a few items here that are specific to WDAT, which we clarified is not subject to the jurisdiction of any state agency. Next slide. Actually, you can skip forward to the next slide and next slide. Okay.

The final section the Roadmap focuses on storage research participation in the wholesale market and determination of the rules on multiple-use applications.

So I didn't go through these items as they went, but as you can see from the presentation, if you pick it up, we're actually making pretty good progress on the Storage Roadmap. So pretty much everything that is within the roadmap the agencies have either done or it is in progress. So next slide.

So this is a brief synopsis of the verbal comments we received at the workshop.

So the first, the California Energy Storage Alliance, presented the need for consistent energy storage permitting guidelines for cities and local governments and presented this as an idea for potential EPIC funding.

The California Hydrogen Business Council discussed the value of including power to gas or hydrogen producing technology in the roadmap.

There were various comments on the interconnection clarifications for distributed energy resource processes or DERPs, which is not specifically a storage issue, but more DER's broadly.

The Independent Energy Producers Association discussed the importance of tracking jurisdictional and transactional relationships in developing rules for multiple-use applications for storage, which I thought was a very good suggestion.

There were various comments and questions specific to distribution level rulemaking, so IDER and DRP and associated solicitations.

The Commission's Safety and Enforcement Division discussed the state safety standards for storage.

There was also a presentation on energy storage college curriculums, so an actual education process is happing in Southern California. Next slide.

I should say this does not include any written comments that have been received to date, so those are just the verbal comments that we got at the workshop.

So these are just my initial thoughts and my initial thoughts alone, for updates to the Storage Roadmap. So one is simple to update with historic and current activities and timelines, some of the items on the roadmap can be removed. Of course, review the priorities and action items and update as needed. Is there anything else we need to do in particular, something I'm curious about. And consolidate roadmap items specific to certain processes, so there's a lot of repetition around distribution-level services and procurement valuation as well as multiple-use applications.

And also, the final bullet is to incorporate the suggestion that we got at the workshop, which is to include discussion of jurisdiction and authority, particularly for multiple-use applications. I imagine that would also be relevant for distributed energy resources generally. Thank you.

MR. GRAVELY: Any questions from the dais for this speaker?

CHAIRMAN WEISENMILLER: It was good. I think the one thing I'll probably ask, so each of you I'll ask the basic question of, "What do you think are most three important things we need to focus on, on storage, going forward?"

MS. MCMAHON: Uh-huh, so one of the most important things is actually something that I'm working on right now, with the CAISO, which is resolving rules for multiple-use applications. So that is the rules by which the capacity from a storage resource can provide multiple services at the same time. So that's the most important thing.

And then there are a number of issues that are within that, so ensuring that there is no double compensation. Ensuring the ratepayers are actually getting what they're paying for and ensuring that we don't exhaust the actual storage resource itself, so I think there's a lot of learning there. And so there's that.

There's one issue that I confess being somewhat new to storage I'm not sure has been dealt with and that is end of life of for batteries. So large, of course pretty much all of the procurement that we're seeing, is utilizing batteries.

Oh, and also the third issue, which is being dealt with on the distribution side, is the ability for storage to provide non-wires alternatives to distribution-level deferral and transmission-level deferral.

MR. GRAVELY: Great, any other questions?

CHAIRMAN WEISENMILLER: No one else?

MR. GRAVELY: Okay. Thank you.

We'll transition to the next presenter.

MS. HOU: Good morning Chair Weisenmiller, Commissioners, Keith and Simon. My name is Delphine from the ISO, the Manager of State Regulatory Affairs. And I'll be presenting an update to the Demand Response and Energy Efficiency Roadmap. Before I do that, I kind of wanted to set the stage for the context of when that roadmap was developed and where we were at that time.

So then thinking back in 2013, some of the main issues that we were faced with was we had these great resources, but they weren't necessarily integrated into the ISO market per se. They existed, of course some of them existed for many, many years.

But the reason why we wanted to integrate them into the market is because we were looking at certain I guess some of the concerns in Southern California haven't quite gone away, but at that time, it was about SONGS. So that was a huge concern that we had on our system. We wanted sort of all the resources available to participate and to help us through that difficult time. We're seeing sort of a repeat of that today with Aliso Canyon. But that was the first instance of it.

At the same time we were seeing a great amount of renewable penetration, so that was beginning to track. The CAISO had put out its duck curve. So those kind of concerns were swirling around losing a huge base load, having more renewable penetration. And then having these resources that were not being asked to sort of perform in the way that maybe some of the more conventional fleet had been relied upon.

And lastly, you know, in this interest of looking at -- especially on the energy efficiency side -- we also had a letter from Senators Padilla and Fuller asking about process alignment. Because as we planned for our new future, we really needed as the agencies between the CEC, CPUC and CAISO to be aligned in our assumptions, so that we were planning collectively and correctly with sort of a common vision and goal.

So that just gives you a context of the backdrop of how this develops. Next slide, please.

So in creating this roadmap there were five main goals. And a lot of what I just said before is sort of the background context of why these goals were selected to be what they are. As Rachel mentioned in our workshop on the 13th accompanying this very simple slide is a larger matrix with each goal there were numerous activities under each goal. So as part of that workshop, we did provide a matrix for stakeholders showing how each agency addressed the various activities under each goal.

But I'm just providing the summary here today. And I wanted to hit the highlights. As Rachel mentioned, some time has passed and I think the agencies have been working collaboratively with a big concerted effort to make sure that we have accomplished these goals and by and large we have. But at the end of this, I will talk about, sort of the evolution of what's coming up next, now that we've gotten through these major goals.

So the first one, to ensure consistent assumptions that really is talking to process alignment that started off with energy efficiency. But that has grown to look at not only energy efficiency, but demand response, which encompasses this roadmap, but across all of the demand side modifiers. So that's embedded today in our process alignment agreement between the agencies that occurs through the IEPR, and the CEC demand forecast is the foundation of the LTPP at the CPUC and also the transmission planning process at the CAISO. You know am I -- later on we'll talk a little bit about potentially where IRP is going, but at least for this roadmap that was actually a great effort to get us all aligned and provide a lot of clarity consistency across the agencies. So that was extremely helpful.

The next one in terms of modifying the load shape to reduce resource procurement, there you start seeing some of the concerns that the renewable penetration was causing the system. And there, there has been a lot of effort in recent years, especially with the default time-of-use rates for the IOUs coming up. There's a lot of discussion about well what should those default time-of-use rates look like. So there was a big collaborative effort between the CPUC and the CAISO to make sure that the CAISO provided its operational information into the CPUC Proceeding, so that all parties would have that record.

There has also been a lot work on the CEC side in getting the funding correct and looking at the duck curve. And making sure that we understand things like over-generation and our ramping concerns. So that effort has been socialized through the agencies, through stakeholders.

It's kind of a well-known concern and there are a lot of efforts being put towards resolving that.

The third goal is clarifying ISO needs for DR and EE. And that has been a great evolution, because from DR and EE that was a little bit of a step away from the planning process. It's much more imbedded today. So for example, the energy efficiency is foundational to the transmission planning process. Demand response and working very closely with the CPUC we do have the Bifurcation Decision, so that more DR will become part of the ISO market. So the deadline for that is 2018.

So we we've already seen a large amount of megawatts in the CAISO market. It has helped us. Like for example on the May 3rd event we did trigger our emergency demand response and a hundreds of megawatts responded to that. And so we're looking forward through the completion of bifurcation when we get all of the IOU DR programs that are meant for the supply side to be active in the CAISO market.

So we feel like that's a huge progress that's been made. We've also worked very closely, talking about flexibility needs, so our initiative of FRACMOO as we call it. And also recognizing flexible capacity at the CPUC, that's been a huge collaborative effort to address those ramping needs caused by renewable penetration.

On the fourth point, ensuring resources are procured, that also has been very foundational for the IEPR in terms of data collection. And we really need that granularity, because as we do more granular planning, not only at the ISO for our Transmission Plan, but as the PUC has talked about their distribution planning, really needing to understand where those resources are down to the circuit level. That sort of data collection, understanding where the energy efficiency is, down to the bus level, all of that work that the CEC has been doing has been incredibly useful to the CPUC and the ISO as well. So we feel that that's a great collaborative effort between the agencies to understand where the system is evolving to.

The last one, the goal is to increase DR program and pilot participation. We've had a lot of piloting, but I think maybe in addition to some of the piloting this is a more technical goal. So we've simplified our metering and telemetry requirements trying to understand sort of more interesting use cases.

I would say the lion's share of it probably is being dealt with in Goal 3, where we're putting more and more of the DR into the market. But to the extent that there are additional cases that we need to clarify, Goal Number 5 has been useful in kind of testing out those use cases. But I think an important one is ultimately working with the PUC and the CEC on trying to get those rules simplified. And as Rachel mentioned on the storage side, the multi-use application is a great example of that. Maybe not for DR and EE, but I think the lessons learned from that storage proceeding could actually be expanded to other resources.

So I'll close out with my last slide to talk a little bit about next steps. So we want to continue to collaborate. So there are many proceedings and avenues where we can do that, but really we want to kind of think about the next generation of demand response. So it maybe to go to where Chair Weisenmiller's last question is, "Where do we see the most important aspects of DR and EE?"

And I would say it's really, especially on the DR side, is how do we operationalize that in the market? So now we have DR participating in the CAISO market. We've called it a few times, but can we keep relying on it over and over again as we do with conventional resources?

And my second point is as we get more DR in the system, it will replace conventional resources. So we want to be able to rely on the demand response as well as we rely on the conventional. So I think putting that on equal footing of not just saying well, there's DR programs, but really having that part and parcel of our planning regime is going to be very important.

So the last part is going to be related to our future grid needs, when we look at what we need for flexibility, for ramping, where the Grid might go, more distributed resources so that we'll have to have a stronger relationship between the transmission and the distribution side. I think that speaks very clearly for you know increased collaboration with PUC and CEC in those regards. So thank you.

CHAIRMAN WEISENMILLER: Yeah, so in terms of following up for a second, I think -- remember back when there was a FERC PUC or the FERC event on passing markets? And I think the thing that got everyone's attention, particularly the PUC commissioners, was looking at the PGM DR, compared to the California DR.

And that got lost in some side tracks about how much that was basically some sort of backup engine type of thing, although I think the PGM market monitors said on the record there was 70 percent of it wasn't that. But again it just was really striking that while being a real leader in demand response, say back in the first Brown Administration, we weren't at this stage.

And there seemed to be very clear message from the Commissioners that they really wanted to up the game. I remember that one business meeting where the PUC Commissioner was saying, "Wait a minute. You're talking about a schedule here, which was longer than all of World War II to get any action here."

And the questions is where are we, number-wise? Are we really making progress? Again, it's great to be having the conversations, but at the end of the day how do we get more megawatts in the demand response programs and being able to use those more frequently and not just those old interruptible deals the PUC did, which basically you never get interrupted, but you got a rate discount.

I mean again how -- where are we in making progress here?

MS. HOU: Sure, so right now, so it is still more focused on the CAISO side. In the CAISO market the DR is still more focused on the reliability aspect of it, so there's over 1,000 megawatts of the reliability demand response. And that is based on a trigger when we need it for an emergency purpose. But we are seeing increasing megawatts, hundreds of megawatts on the economic demand response. So I think that's going to be the DR that really participates in the market, helps us reduce our demand needs.

And we're hoping that through efforts like DRAM, which is procuring a lot of this on the PUC side and then offering that into the CAISO market, that's a good relationship. So that we do see increasing penetrations of that, but based on economics and it's not being held back for reliability.

MR. CASEY: Chair Weisenmiller, if I might?

CHAIRMAN WEISENMILLER: Yes.

MR. CASEY: You know, I kind of -- your comments resonated with me, because when I look at where we are at with DR today it largely looks like the DR programs we had 20 years ago when the ISO started. There are some new programs coming in and I certainly agree with Delphine, we're integrating more of them into our market, and that's a good thing.

But really that next generation that she's talking about is demand response that we can call on every day that is helping us with the integration needs on the system, helping us with the duck curve. And that requires a demand response that's seamless to the customer. It's really leveraging the latent flexibility that large consumers have or aggregations of consumers have.

And I've seen some very interesting applications of that in Europe, where I think they're far more advanced. It was like the Tesla DR in terms of the control systems they put in large commercial industrial operations where basically it's invisible to the customer, And they just say, "I don't want you to impact my business. You figure out what my latent capability is and you manage it. And if you can reduce my energy costs, great."

So the technology, the capability exists there. I think the frustration is California has not really availed itself to really tap into that. And I'm not sure what the answer is in terms of how we do, but it sounds like Delphine has it.

MS. HOU: I don't have the answer to everything, but I did want to add -- so Keith when you bring that up, I do want to add that we are seeing more and more storage resources participate as proxy demand response. So maybe a storage resource would have that capability for daily bidding into our market to provide demand-response there. So that would be a way for consumers to take advantage of that, but they don't necessarily see the impact of that on their day-to-day operations.

CHAIRMAN WEISENMILLER: Again, and I know this is something that Andrew's passionate about and will come up with more in July, but the thing that really hit everyone at that workshop was that here's PGM, it's 10,000 megawatts. The only difference is size, there is California; 2,000 megawatts sort of where we have been historically. And we weren't using that much. And we weren't sure how much, if we asked anyone to do anything, they'd actually do it. So we seem to have ramped up the program, so we at least have some comfort that is there.

But trying to get to the -- ideally, as we have more and more variable renewable resources, it would be good to have more and more variable load to match that. So that gives you a scale again.

If we can get to say 10,000 instead of a couple of thousand, it's really a game changer for us. And again, I think as we go forward, I think that's certainly where I believe talking across with President Picker, Steve, I mean that's where people want to get to is more that level as opposed to the current couple thousand.

You know, I mean certainly the May 3rd event should have been a wake-up call for all of us that as you get into these evening hours and you have solar dropping off fast and you have load going up fast, you could have problems if anything trips off or doesn't show up. And at that point, we would much rather have load that you have set up to drop, as opposed to just dropping load because you have to.

So again, I think there's been a consistent message from all three agencies to the staffs is that they've got to really start thinking outside the box to move the needle there. And again, it's not just more of the same, but how do we really take the quantum jump?

And I do agree it's very good that we've also, having said that are moving away from saying, "Here's the box storage. Here's the box demand response. Here's the box energy efficiency." But looking at more combinations of stuff. Yeah.

MR. BAKER: I certainly appreciate the comments and I think the PUC is grappling with these same issues. Just a couple of things, one is on the PGM versus California and this question of how real is the demand response and to what extent might fossil fuel backup generation be contributing to that? And so the PUC took some pretty major steps recently to implement a new prohibited resources policy for demand response programs, and implement a variety of detailed implementation rules to enforce those as well.

So I think we'll be seeing to the extent that there were any of those resources in our demand response, going away. Delphine mentioned as well the demand response auction mechanism, which is in some ways that's the PUC's effort to try and jump start this effort towards bifurcation in getting all of the demand response resources bid into CAISO markets. And that's providing us a real opportunity for learnings about how the operational impacts work.

But to Keith's point we're well aware that there's a need for this next generation of DR to be figured out somehow. So that was one of the reasons why we did this potential study with the Lawrence Berkeley National Labs that some of you may be aware. And one of the opportunities that they really identified is -- they call it "shift DR". So in essence that's either through pricing strategies or perhaps through wholesale markets, finding ways for pre-cooling or other scheduling of manufacturing, storage or course, to shift loads to address the duck curve.

And for my part I think the real key top that is as you said, Keith, is to make the DR basically invisible to customers. And so how do we get DR built into buildings and then aggregate it over large enough areas where very small quantities of DR in buildings aggregated over large areas have a big impact on the system, but have virtually imperceptible impact to the customer? And I think that's really this coordination with the Energy Commission in your code process and some of the control strategies that you guys now have coming into your Title 24 process.

I think there's a lot that we can continue to collaborate on there to more effectively bring that to the marketplace, ensure that that's actually getting deals out there in the marketplace. And we'd be open to further conversation about how the PUC can be helpful in that space as well.

CHAIRMAN WEISENMILLER: I should (indiscernible) there were rumors at the Clean Energy Ministerial in Beijing. I was on a panel on basically digitalization and the Internet of things and how that can effect energy efficiency. And I guess in a way that's the next big thing, or at least outside of the Trump sphere of the next big thing in DC is that sort of chatter. And so certainly there's a paper coming out from Amory's folks and the X. MacKenzie (phonetic) guy in about two months that basically is saying maybe 20 percent savings if you do a digital connection.

I was sort of the skunk at the picnic since I was raising the question if you put everything online all the time, how much are you drawing in vampire load, which has been certainly one of our concerns here. And again people didn't want to think about that as much as the technology. But again the technology option is coming there, which could again enhance the demand response.

And people, having said that again echoing Andrew's concern about how do we make all of our buildings basically part of the solution by building in more flexibility there? But again we can't just continue doing more of what we're doing and somehow claim that demand response is going to be the solution.

MS. BROOK: Right, so this is Martha Brook. I have two things. One I wanted to respond to Simon and you the Chair. Absolutely buildings need to be part of the solution and part of the market. One of the issues we have in the Building Code is you have to prove that any investment in the building is cost effective. And so it's sort of like the cart before the horse, in a way. It's sort of like there has to be a market for us to be able to say it's cost effective to add control functionality and demand response functionality to buildings because that way they can play in the market, right?

So it's almost like you can't, as a mandatory Building Code, put assets into those buildings that may become stranded because there's no persistent market. And that's the issue we need to all work on together. It's how do you have a sustainable persistent market and therefore you can justify many more demand responsive technologies in Building Code. So that's one thing I think we need to work on together is how do we prove there's a market, so that we can make that justification in the regulation for the Building Code to add that functionality into buildings?

CHAIRMAN WEISENMILLER: I think the other thing we need to do, which we talked about in the SONGS context, but because of what I would say are jurisdictional issues never happened is whenever we've done a solicitation for something, be it generating resources, being it storage or anything, I'm always amazed by the response, the price and the quantity. And so in the SONGS context, the idea was okay ISO, somebody just go out and just do an auction and see how much demand response we can get.

And we still stay what's sort of our characterized more utility-centric programs of doing it as opposed to saying somebody, PUC, ISO, somebody just go out and say here it is. How much demand response will you give us and really harness that innovative capability in Silicon Valley and elsewhere to see if that's part of the quantum jump.

MR. BAKER: Yeah, and I think that's one of the reasons why the Commission authorized the Demand Response Auction Mechanism Pilot, which is a third-party demand response program, on the hopes that the third-party marketplace could perhaps help to grow the DR marketplace. And so we've now authorized the third solicitation for the 2018 auction and -- was that a bird?

MS. BROOK: I thought I heard a bird. I thought it was somebody's phone, but it might just be a -- yeah, oh! (Laughter.)

MR. BAKER: And we will be evaluating that program in 2019. And certainly the Commission has high hopes for that.

CHAIRMAN WEISENMILLER: Great.

MS. BROOK: Can I ask one more question of staff?

So this is kind of in the weeds, but I went to the workshop on the roadmaps. And having heard you again today, I'm really curious about -- in my opinion, in order to scale efficiency and demand resource as resources, we need to tackle that measurement of savings issue.

And so I'm wondering, have you already solved that? Is that getting solved in the proceeding or are we also still working on it and we're just not talking about it?

MS. HOU: I'm not going to be able to speak to the measurement of savings, but for energy efficiency the way the CAISO looks at it is that we have our agreement between the Joint Agency Steering Committee to have a certain amount of energy efficiency embedded in our transmission planning. So we just assume it will be there, so that's how we address it. I don't know if other folks wanted to respond?

MS. BROOK: Yeah, I guess I was thinking about when you said that one of your primary goals is to operationalize efficiency in demand response, it seems to me that you have to have the ability to measure it.

MS. HOU: Oh, I see.

MS. BROOK: And since we have AMI meters now and we have very granular data, so you could do "before and after" types of savings. Is that in your plans or do you think you already have it figured out?

MS. HOU: So for energy efficiency, that's a good clarification. Let me split the two. So for energy efficiency, we just assume that as part of the demand forecast that we receive through the IEPR process.

On the demand response side, because they participate in our market, we do have measurements. So we would give them an award and say, "We expect you to drop load, five megawatts tomorrow." And then we can look to see if they actually provided that response.

One of the things that we've been working on is -- that sounds very simple, but one of the things that we worked on are more collaborative discussions with the PUC and with a lot of the DR providers -- in how to establish baselines. What that looks like if you're establishing a baseline for, let's say more traditional demand response, like industrial load dropping or if you're a battery. And actually that starts to flow into the multi-use application discussion, because it will be a collaborative effort, because the battery might be used for the wholesale market. But it could be used elsewhere for, let's just say behind-the-meter usage or maybe there's a distribution need. So those are the things that we're trying to map out.

Today, the more simple answer is we provide a schedule, we're expecting a certain amount of load drop, and then we measure to see if that occurred.

MR. GRAVELY: Thank you, sir.

We'll go to the third panel. Noel, one second we'll get your presentation up. Go ahead, Noel.

MR. CRISOSTOMO: Good morning, everyone. Thank you for having me. My name is Noel Crisostomo. I'm an Air Pollution Specialist in the Fuels and Transportation Division of the California Energy Commission. And I'll be providing an update to our progress on the Vehicle-Grid Integration Roadmap.

For those of you who are unfamiliar with the concept of vehicle-grid integration, it is the use of vehicle and charging intelligence to control and reduce the cost of electrification by doing smart charging and eventually vehicle to grid. There are key aspects to enabling the cost reductions.

First reducing the cost of customers to fuel their electric vehicle; reducing the infrastructure demand on the distribution system to minimize impacts; to improve system visibility and to charging and mobility requirements, so that we can absorb and dispatch vehicles to absorb renewable energy. And again the ultimate goal of this concept is to reduce the cost to customers and society to accelerate the adoption of EVs using clean energy.

In the context of the VGI Roadmap, we started this process through workshops among the three agencies: the CEC, PUC and ISO, beginning in 2012. And it'll be helpful for me to contextualize why we started this.

This was a response to the Governor's ZEV Action Plan and his executive order requesting infrastructure to support one million zero emission vehicles by the year 2020.

Back then, there were only a handful of vehicles including the Chevy Volt and Nissan Leaf. Those only went 20 to 80 miles on electric-only range. And now we have more than 30 coming now or in the next few years, which can go up to over 200 miles and are much more affordable in the mass market.

Furthermore, our charging networks were not as diverse as they are today. And there was not a standard for the American and European cars for DC fast charging at that point, the combined charging system. Essentially, we can charge seven times as fast as when we were planning for VGI back then.

In addition, when we started the roadmapping process there were limitations on the utility roles in deployment to charging infrastructure. In 2014, the PUC had removed a prohibition on the utility investment and ownership of charging systems. And in 2016, the PUC approved 12.5 thousand charging stations to be deployed through the first phase of Y2D infrastructure programs. Of course, charging infrastructure is a necessary component to achieve grid integration and dispatchability of our electric vehicles as storage devices.

In addition, in 2012 the EPIC Program was still in process among both of the agencies. And EPIC and the DR pilots that have now been concluding were critical elements to inform our validation of the EVs as grid resources.

We now have more than a dozen key pilots that are informing our use and technology designs in order to incorporate this into both vehicles and charging systems and upstream to the utility use and ISO.

Yet another key aspect that was not available and was a key request in the roadmap was understanding the value in markets for vehicle-grid integration and demand response and smart charging. As Martha was saying, we need both the cart and a horse to send a signal to automakers, charging providers and everyone planning around those loads, what is the economics that will drive investment and planning in our devices.

So CAISO had not yet started the Metering and Telemetry Initiative, or the DERP aggregation processes, which are now completed and submitted through recent FERC tariff approvals. In addition, the PUC had not yet started its efforts in distribution resource planning, integrated distributed energy resources, or most recently per SB 350, the integrated resource planning process. So all of those are complementary efforts that provide a market for the use of EVs as grid resources.

And then finally, the policy developments surrounding SB 350, and the April confirmation by the ARB finding that the Advanced Clean Cars Mandate will continue on its course. And beyond, in a 2025 and forward program, is critical to showing that we will maintain our deployment at increasing levels of electric vehicles and hydrogen fuel cell vehicles to meet our climate and clean air goals.

And one thing was not included in the VGI Roadmap, which primarily looks at light-duty vehicles, but has increasing importance per some of our testimony during the April workshop, was that medium and heavy vehicles are viable today. And especially in the bus and short-haul delivery use cases. Considering the potentially orders of magnitude of greater load in order to serve the duty cycles with those high-power uses and heavy-weight uses, that improves the need to understand how to manage this resource.

So how did we set forth on solving these problems? The three agencies work together in a collaborative process to address three major areas. First, to determine the value and potential of grid integration by examining use cases, the impacts to the electric grid, and the market potential and finding those over time in order for us to understand how to characterize the load.

Second, to develop enabling policies, regulations and business processes, in order accommodate them through rates or procurement programs or infrastructure deployment and dispatchability into the markets, both utility side and the ISO.

And then third, to support both Tracks 1 and 2 through developing the new technologies that are needed to ensure interoperability, higher accuracy in measurement, and improvement in the performance of these as actors in our grid system.

I won't go into the detail that we previously discussed during the June 13th workshop, but specific activities and progress are outlined in the agenda over four slides. So next slide, please.

Here I characterize party feedback from our previous workshop, suggesting how we might continue on the VGI Roadmap with timely progress, while also incorporating all of the policy, technology and other learnings that has happened in the past five years since we started this effort.

The first point is to make sure that our rate of vehicle adoption and charging infrastructure deployments accelerate beyond current rates, in order for us to meet our ZEV Mandate goals. We would have to increase the rate of adoption several times over in order for us to meet CARB's eventual midterm requirement of 4.2 million zero emission vehicles by 2030. Right now, we are approaching the 300,000th electric vehicle and so 13 years is not too much time to bring that curve up. So we want to make sure that our VGI efforts are complementary to that and do not slow that down.

Second, we have to ensure customer simplicity, so that we aren't confusing the customer when we serve dynamic rates that might change on the hour or the day of, so that they don't have a negative charging experience. We also need to understand how third parties can work together with utilities to bring these resources into the market to potentially simplify this process for them.

Third, we have to use our data collected through pilots and not only our data, but data through national labs and the automakers and other jurisdictions throughout the nation to inform our infrastructure deployments and designs.

Fourth, an unanswered question that I'd alluded to before is the need to understand and inform the value of grid integration, so that automakers, charging providers and utilities can design programs, products and equipment and put them into service altogether. And actually code design-integrated circuits and software systems to put these all together.

Another point that was raised during the workshop was the need to modify the Electric Utility Rule 21, which regards interconnection of distributed generators onto the distribution system. Right now, the Rule 21 requirements are designed specifically for stationary devices. And of course vehicles are not stationary devices, nor do they usually get UL certification. But there are potentially equivalent human safety and electrical protection requirements that are designed through the automotive regulatory and certification bodies.

This is needed in order for us to realize a vision where vehicle to grid is possible, wherein some research has shown that if vehicles are adopted at the levels that CARB has outlined for us, in their highly renewable penetrated world, vehicle to grid could replace the need for stationary devices.

And lastly, a comment from Lawrence Livermore National Lab highlighted the need for the VGI Roadmap to address the potential internet protocol-based attacks on electric vehicles and cyber-attacks from men in the middle or external forces that are trying to control our loads and hack the grid. So cyber security needs to be a future addition into our progress on the roadmap.

So in response to these, and this is just a staff proposal at this point, there is a need to update the VGI Roadmap to accept and incorporate all of the progress that we've made in the past five years. First, it should reflect the new 2016 ZEV Action Plan and new laws under transportation electrification for SB 350, which includes markets and also the progress in market designs, utility procurements and incentives.

Second, we have to synthesize our prior research that has been completed through EPIC and other resources, in order to coalesce the industry, so that we can scale.

Third, we have to align our updated charging infrastructure demand modeling, which is a successor to the NREL 2014 Report. It's called EVI-Pro. My Colleagues in Fuels and Transport are working on that right now. And to align it with our deployment strategy according to those models.

Fourth, we have to consider the outputs of an ongoing interagency VGI communications protocol working group, which is trying to understand the ins and outs of implementing different standards to ensure interoperability for our systems.

And fourth, we'll need to coordinate with R&D staff on a forthcoming technology roadmap related to transportation.

To Chair Weisenmiller's request for three points about the most important things that we have to address, first is the need to establish interoperability, so that our vehicle resources in any situation, can be certified as a demand response or eventually storage device. This could be detailed in at least three demands: seamless public network interoperability; second, different charging situations whether it be charging at home or at work or fast or slow and then third, integration with larger home and building energy management systems, so that they work in concert as a suite of other building side or other loads around it.

A second issue is again, value. Because automakers, charging providers and utilities need to develop business plans and programs in order to establish what they have to build inside their charging infrastructure and on board the car. This is a critical element to achieve interoperability.

And then third, we have to synthesize our technology plans in R&D with our deployment planning of infrastructure. For example, we met with the ENERGY STAR Program led by the federal EPA. They've recently certified the first charging systems under the EVSE Certification for ENERGY STAR, for reducing the vampire load and ensuring low power while also allowing for optionality in DR and communications connectivity requirements or voluntary options for certification. So that is one potential way of looking at how we coordinate both our technology design and our broad deployment design.

Next slide, I guess is the conclusion. I look forward to your questions and advancing the progress on our roadmap.

CHAIRMAN WEISENMILLER: Great. No, I want to thank you for that particularly for providing a lot of leadership here. I think the challenge in part, I mean beyond (indiscernible) is of the various roadmaps, this is the oldest one and there's been a lot happening. And so as we go through the updates, this one has to come together with a lot of attention across the agencies to really move this forward. And just having said that, I would point out some different issues.

First, is one of the things that should really be part of it is the Volkswagen settlement. As you know, the last ZEV Action Plan sort of came out just before that was put in place and how does that really affect the landscape on stuff? On all or our programs it's just a lot of money. It's hard to say our ARFVTP funding on some of the chargers, it's like how does that fit -- I don't know -- with that settlement in place?

The other one is just to say we have two goals in this area. One is greenhouse gas emissions. And generally we're making a lot of progress on greenhouse gas emissions. The 2015 numbers for power, you know again, we're well over 20 percent below the 1990 levels. Transportation is 40 percent and we're not making much progress there.

If you look at the other metric on reducing petroleum by 50 percent, by 2030 we haven't touched that at all. I think it's probably up in recent years, so this has really got to ramp up a lot. And so I think this plan has to really have that vision.

The two points I would make is one, we have this challenge going forward, particularly on the VGI. I remember we had a CC conference where it was probably one of the few times you had the OEMs and the utilities in one room. And the utilities were like, "Oh, these are the various options you can do, so your charging. You can deal with the cost if you do it at night, if you do it in duck curve, you know and blah, blah, blah, blah, rate designs are changing, blah, blah, blah blah."

And the OEMs were saying, "Oh, my god. You know, our dealers have somebody come in and they say, 'Okay, do you have the red Volt, versus the whatever?" Okay, these are the three cars we want to sell you. We want to sell the car pretty fast, so we can have it low in price.

So the notion that somehow we're going to say, "Well, these are all the ways you control the costs of charging. And if you're really smart," but we have to be very careful because of the liability to say God knows what the PUC's going to do on demand charges. And so this could all be different. It's like there's got to be someone there who just makes it easy. And not something that you have to basically have you or someone from the PUC sitting next to you as you're making your buying decision, right?

MR. CRISOSTOMO: I agree.

CHAIRMAN WEISENMILLER: And so on the one hand, we want to integrate these resources into the mix, because they're both on the charging or storage side, they're going to be huge. But how do you do it in a way, which doesn't just stall out the consumer acceptance? And that's a challenge for you in the plan.

The other thing that sort of you need to think about some is we're 40 percent of the U.S. market. And you're talking about some of the things that are going on, just standardized charging in the U.S., and some of those basic issues.

You know, the Governor, Mary and I were in Beijing. And part of President Xi's major initiatives is the Blue Sky part. And if you've ever been in Beijing, you know it's normally not blue skies. And so there's a real push there to go to zero emission vehicles fast. You know, basically at this point in tax season, Shanghai and Beijing, they're going to be electric, period. Buses in the cities, they're going to be electric buses. If you want to buy a car in Beijing today, you can either buy an electric car tomorrow or you can get in a lottery and sometime in the next few years, you might be able to buy an IC car.

So the basic question is how do you make sure, as we're standardizing some of this equipment, we're standardizing with the Chinese, who would love to mass produce and just flood the markets at that scale. And so that's something that certainly Mary came back very focused on, on the China connection ZEV.

I was not as focused on that part of the Chinese connection, but again I think you have to be thinking here again, how do we use the Chinese push in this area to drive the scale to reduce cost and really help us move the needle here in this area? As you said, this has to -- our vision on how we're going to get to 2030 in this area, again has to be a quantum jump up from where we are now.

MR. CRISOSTOMO: Right, I can answer all questions at once or --

(Off mic colloquy.)

MR. CRISOSTOMO: Sure. So agreed the Volkswagen

Settlement is a key complement to a number of other programs, both internally at CEC with the ARFVTP and the other incentives along the ARB and PUC efforts. So we are in continuously engaging with interagency staff on planning the different efforts to incentivize infrastructure deployment.

You're absolutely right around the lack of progress on the petroleum reduction goal. I would also note the air quality mandates in the South Coast and San Joaquin Valley requiring 80 percent reductions in NOx emissions by 2023. So essentially our 2030 target has been cut in half for those areas. And in order for us to seamlessly have high deployments without confusing the customer you are right around the need for a potentially third intermediary between the end use customer and the utility to supply rates.

The way that SDG&E had plans for that in their Vehicle-To-Grid Integration Pilot now called "Power Your Drive," in which they're serving an hourly CAISO rate to individual customers that actually flexes on a day of, based on forecast error -- and is differentiated to the circuit level for an individual customer -- is by having EVSP qualify to accept that rate, to simplify it in the actual service that they're providing to the end user.

And then related to the U.S. market share, California is the largest American segment. But agreed the implication as I'm looking at China for VGI and California is twofold: both the need for coordination among what is being built across the United States and across Europe and potentially Asia for standardization. And the potential effect of the Chinese market to blow out the bottom of the floor for the cost of batteries, similar as what they did to the solar market in 2010-2011.

So that potential effect of non-linear increases in the rate of vehicle adoption is a good hope. It's an upside risk. But if we are not ready in our distribution systems to accept the power that we are giving away for free, or paying other people to take right now, we have to make sure that our infrastructure is interoperable with cars in a way that accepts all that power without confusing the customer. At a rate much faster than we're expecting right now, so yes I agree with all of your points.

CHAIRMAN WEISENMILLER: Again, GM sells more cars globally in China than in the U.S. So again certainly California is a big part of the market they have to deal with in this area, but they've got to deal with China too. That's the bottom line.

COMMISSIONER HOCHSCHILD: Do you have anything further or can I jump in? Okay. Yeah, so first of all, Noel, let me just thank you personally for your work and your team's work on this issue. It's really welcome. And you're experience at the PUC is really appreciated as well.

You know, if you go back and look, you made some solar costs consultant to some wind costs. It's interesting, almost every government agency from the International Energy Agency to the Energy Information Agency and others, when they were doing price predictions over the last 10-15 years, they were off by an order of magnitude. They failed to predict what actually happened in the market.

And I actually think that we're -- I see a lot of the same dynamics around lithium ion battery costs. It's really important to calibrate to what's happening now. Because you have all of these industries from laptop computers to cell phones to EVs to home energy services, all pulling on the same technology basically. And that I think is a real advantage as we bring down costs. And my visit to the Tesla battery factory, which as you know is the second largest building in the world, that they're building. I mean, that's how you get costs down. You get the scale. So I personally believe we're going to see some very similar dynamic to lithium ion as we saw with solar and wind.

A question for you, if you look -- one of the most interesting developments in renewables, which relates to this -- is the ISO study that happened this past spring. Of the 300 megawatts per solar project, where they're basically looked at the services that could be provided to the Grid, through these inverters of voltage regulation, frequency regulation, regulator ramp up and really highlights what we've been talking about for a long time.

We want to be installing smart solar and not dumb solar, but the same things goes for EVs. And right now, it's basically binary. You can set your charger or your car to either turn off or turn on at particular times of the day. But we don't, for example have, that I have seen in any app is the ability to ramp up slowly. And I guess my question is how much is that needed, possible, and if you do it does it need to happen at the charger or in the vehicle? Those kinds of features, because obviously we want to -- It's a huge investment to get a 60 kilowatt battery in all of these cars and the you want to be making maximum use of that to support the Grid as Keith has talked about.

MR. CRISOSTOMO: Yes, I'll take that in two parts. First on the battery costs, and second on the value of intelligence.

The possibility of battery costs dropping much faster than we're expecting is absolutely right. That caused me to take a full industry forecasting kind of metacomparison. I found even on the highest end the Norwegian oil company Statoil has in their renewable case, which is based on advanced clean energy and climate policy, an oil company found that in 2030 60 percent of car sales could be EV. That is much larger than any other forecast in the industry. So I do believe that we would be ill prepared if we're not thinking in those terms.

In regards to the potential for intelligence, that is an ongoing discussion among the agencies and our communications protocol working group. The need for "high-level communications" between different entities in the charging chain, going between the utility to BEMS or Building Energy Management System, to the charger, to the EV at the end point, the combination of who is involved and what information is sent and where is an ongoing discussion with industry.

So we have been competing with the utilities, automakers, technology providers, charging network aggregators and more, in an ongoing biweekly fashion.

MS. RAITT: So I'll just make a quick time check. We are behind schedule if we want to...

MR. CASEY: Well, just quickly, so we can move on. I think when you look at the challenge we have with just meeting the EV adoption targets, that should be I think from a GHG standpoint the first and utmost priority of what does it take to incentivize we're in a different world than China. We have to incentivize people to do things.

CHAIRMAN WEISENMILLER: Mary took a lot of notes.

MR. CASEY: So and then to the extent we can make progress on EV adoption, time-of-use rates would be huge. You could, from a grid integration standpoint, if we can get people incentivized to charge, workplace charging, middle of the day charging instead of when they come home at night, that would help hugely with the duck curve and the integration challenge.

And then the nice to have is the dispatchability. But as Noel highlighted, that's complicated. And you don't want to have that nice to have ultimately be an impediment to getting the first thing, which is the EV adoption.

So I think of it much like demand response that there are a lot of people that are not going to be interested in demand response. But time-of-use rates could incentivize shifting in consumption. And I think we should be thinking of EV vehicles in much the same way.

And maybe target for vehicle-to-grid integration sophisticated operations. You know, major companies that maybe have a lot of workplace charging that could avail themselves to that kind of complexity or commercial operations. You know, you mentioned commercial vehicles eventually being electrified? So you'd get the biggest bang for the buck going after those big operations. And with consumers if we can at a minimum incentivize them charging at the right time of the day, it would go a long ways.

MR. CRISOSTOMO: Right, so I'd agree. We're examining the costs of intelligence. And one of the benefits that I've found is that the technology needed to do the high-level communications and dispatchability is the same technology that is needed to let you throw away your deck of different network cards to authenticate charging sessions. So there is a possibility of having your cake and eating it too.

MR. BAKER: I had a few questions, but in the interests of time, I think I'll hold them and just make a couple of comments. One is that we discussed the updating on the roadmap and a thought came to me that we have the three agencies here, but there's also the transportation planning agencies, which I think would be really important to bring into that. Because there's a set of expertise there that our agencies don't have. So I think outreach to them next time this gets updated would be a good thing.

And then secondly on kind of going to scale you made the comment, Chair Weisenmiller, about China. And I think there's some opportunities as well here in the U.S.

to collaborate with other states. I know the PUC recently signed an MOU with other Public Utility Commissions of Washington and Oregon as well. We had an inter-staff meeting recently. And one of the points of collaboration that was discussed there was around electrification. So to the extent that multiple states can be working together to go to scale on these fronts, I think that can be helpful as well.

MR. GRAVELY: Okay, thank you.

And I'll thank the panel here. And we'll go ahead and have Simon and Gabe come up to the panel, for the second panel.

MR. BAKER: I'm going to put on a different hat and go sit over there.

MS. RAITT: So our second panel is on the CPUC DER Action Plan Update. And Mike Gravely will also be the moderator.

MR. GRAVELY: Well, as we make the transition, last month, the PUC did approve in May this DER Action Plan. So this panel will talk about both what's in the Plan and the activities that are ongoing in the future. Simon will be speaking first on that and we'll get the presentation up.

MR. BAKER: Thank you, Mike. Next slide, please? So just take the opportunity to provide a brief introduction about the DER action plan. And then I'll follow on into some status updates in the rates and tariff's area, followed by Gabe's remarks on status updates for the distribution, planning and interconnection and procurement area. And then I understand there's going to be a series of presentations, non-PUC presenters, about issues related to the third area. The third track of activity, which is wholesale market integration and interconnection. Next slide.

So just a little background on the impetus for this plan. Back in late 2015 and early 2016, the Commission saw multiple fronts of activity ongoing at the PUC and also in our coordination with the ISO on things like storage and demand response and through the EPIC investment plans with the CEC. And we saw a real need to kind put everything into one document and provide an overall vision for where the PUC saw these DER activities headed, so that we could have a target to shoot for in multiple proceedings working on these activities.

And so over a period of time, in collaboration, that came together and it was endorsed by the Commission in November of 2016. It's being administered through not a formalized process of Commission adoption of the document, because we recognize that the plan needs to be a living document. And it's really being used more for coordination purposes across proceedings. So the document sets a long-term vision and then identifies where the supporting policies are that can support that long-term vision, identifies what gaps there and then sets forth a number of priority actions. And then establishes a coordinating framework across the implicated proceedings. Next slide, please.

So as I mentioned there's a number of proceedings that are implicated. The current count is about 15 different PUC proceedings. And it's a real test of your knowledge of the California regulatory landscape to be able to pronounce and let alone memorize what all of those proceedings are. So we recognize that for stakeholders, there's real value actually in pulling this altogether into one document. Believe it or not I think it only hits like 10 or 11 pages.

And we also recognize there were a couple of key CAISO stakeholder initiatives that were ongoing as well. And so we did incorporate those.

An important point to emphasize here is that this document is not a decision-making document, so it doesn't determine outcomes. It sets an overall vision, but then the individual proceedings are where the outcomes are actually determined. But it does provide a platform for common understanding and direction and it stimulates this coordination across multiple proceedings. And how that's really being done and implemented in practice is we have an internal coordinating committee across various relevant sections within the Energy Division and then also within an ALJ Division management.

And as I'm sure folks are aware, we do have Bagley-Keene and important state rules that we must abide by. And so this is our way of effectively working within state rules and yet getting to coordinated outcomes. Next slide.

So there are 17 overall vision elements. And 35 action elements within the Plan. And they're grouped into these three tracks, next slide.

The first track has to do with rates and tariffs. And there's a vision element with regard to customer choice. And this really gets at the need to have multiple rate options available to customers to enable consumer choice and then also ensure that there's the necessary education for consumers, so that they're aware of the rate options and can make informed decisions.

The second vision element has to do with ensuring that rates are marginal-cost based. And to the extent possible they're time variant. Again, with consumer education the goal is to ensure that customers can benefit on the rates that they are on.

The third vision element has to do with innovation in this space. And it recognizes that with the introduction of distributed energy resources, customers can now get on more sophisticated rates, more complex rate designs. And with these technologies they can benefit from those rates, while also benefitting the Grid. And so it's looking to create more flexible processes for innovation in this space to come forward in the PUC's process.

And the fourth one here has to do with just traditional rate-making principles of cost causation and especially with the focus on how demand charges are structured.

And then finally ensuring that rates remain affordable for all, in particular non-participating ratepayers. So this really gets at the issue of the ratepayer impact measure test. Next slide.

In the second track, related to distribution planning, infrastructure interconnection and procurement, there's a vision element regarding transparent planning and sourcing. And this is looking at how we can integrate distributed energy resources into distribution grid planning in particular. And then provide mechanisms by which sourcing of DERs can be done to provide non-wires alternatives, in that distribution space.

There's another vision element here with regard to aligning utility incentives with DER growth and recognizing that the utility's revenue model does depend on, to a great extent, on the rate of return for capital investments on traditional distribution infrastructure.

The third vision element here has to do with leveling the playing field for all distributed energy resources and breaking down silos. And encouraging competitive markets of technology neutral strategies to provide ratepayer benefits.

There's a vision and element here with regard to valuation. And this is always really tough nut to crack. The goal is to get the value right, when it comes to distributed energy resources and that includes the locational benefits, both in terms of the transmission and distribution deferral value. But also in terms of the long-term GHG value and the renewables integration value. And those are all challenging components to analytically get to quantitative methodologies to be able to reflect the full value of these DERs on the Grid.

There's a vision element related to streamlined interconnection. And there are a number of ongoing efforts to further encourage streamlined interconnection.

There's a vision element related to the incorporation of DERs into the Grid, to maximize ratepayer value. This is really pursuant to The Distributed Resource

Plan process that was set out in AB 327. And it's manifesting in multiple ways, but in particular with regard to a proposal for a deferral framework, whereby the utility's distribution planning process would be opened up to a more formalized annual review process and then identification of opportunities for candidate projects that could be deferred through DER alternatives.

And then finally, a focus on data communications and cyber security.

Track 3 is related to the wholesale DER integration space and interconnection at the wholesale level. And so we have a vision element here on encouraging robust participation by DERs in wholesale markets. And many of the activities that are ongoing with regards to demand response and bidding those resources into CAISO markets as well as storage fit within here.

There's a vision element related to multiple revenue streams. And this gets right at one of the topics that was discussed earlier, about multi-use applications for storage and so forth.

We have a vision element related to the interconnection rules and market rules supportive of behind-the-meter distributed energy resources. And this gets to some thorny issues in terms of where the FERC jurisdictional WDAT fits in versus the Rule 21 interconnection rules. And whether and to what extent behind-the-meter resources can play in wholesale markets.

The fourth has to do with electric vehicle user behavior and being able to better predict those and then be able to fit that into grid operations.

And then finally, there's a vision element related to non-discriminatory market rules for electric vehicles.

So that's what I had for the initial overview here. I'd be happy to take any questions at this point before I proceed into the status updates on the rates track.

CHAIRMAN WEISENMILLER: Again, I'll just ask the basic question of what would you consider the three most important steps here?

MR. BAKER: Well, I would say that probably one of the more important steps is this valuation work. And that's work that I'm very familiar with. And it ties in closely to the Commission's anticipated revisit of the Net Energy Metering Rules currently scheduled for 2019. And so the Commission, in its decision adopting the successor NEM tariff, said that it would revisit Net Energy Metering Rules in 2019. And that it would look to the Distributed Resource Plan Proceeding in its process to determine what the locational value of solar resources and other NEM resources is to more fully flesh out the valuation framework for determining NEM policy.

And so that work is ongoing in DRP, but it's not easy work. And so we really need to keep a close focus and make sure that's moving forward apace, so that we can timely have that data available for the NEM review.

Another area that I think is really important is non-residential rate design. And this ties in very closely with some of the electric vehicle strategies and some of the challenges in terms of ensuring that we get this balance between the customer and the ratepayer interest, in terms of how rate design is structured.

Current non-residential rate designs with coincident demand charges can be prohibitively expensive for electric vehicles. And utilities do have some pilots to provide some exemptions and waivers to enable that. But we still don't yet have a broad based policy framework for rate design that addresses some of these issues related to non-residential demand charges.

And then I would say the third area really has to do with integration with the PUC's integrated resource planning process and how that then ties back into the linkages with the planning at the CAISO and at the CEC with the IEPR process as well. So to the extent that the IRP process, for example, through its optimization analysis reveals perhaps some different pathways to achieve long-term GHG goals at a lower cost that have implications for current DER policies. How do those then get worked through the DER proceedings in an effective way?

CHAIRMAN WEISENMILLER: (Indiscernible)

MR. BAKER: All right, so I'm going to just give some brief updates on the first track in the DER Action Plan related to rates and tariffs. And the first has to do with work that we've done to look holistically at the time of use periods.

There was an order instituting rulemaking, which was established in 2015. And this was done in close partnership with the CAISO. In fact, there was some work that was done in partnership with the CEC as well in the IEPR process to develop a joint agency report on time-of-use periods. And within that some ideas surfaced, and some analysis surfaced about appropriate rate designs to help to absorb excess renewables during periods, during the springtime for example. And also to look at shifting peak periods later during the day to address the duck curve issues.

And so the CAISO actually had a white paper that informed initiation of this proceeding. And the PUC ultimately adopted a decision in 2017 that provided some policy guidelines for setting TOU periods within the GRC

Proceeding. So this was like an overall set of guidance, so that in subsequent GRC filings, as the utilities brought forward analysis and as the parties engaged, there could be a consistent set of principles that were applied.

That included some grandfathering rules to be cognizant of the consumer acceptance and consumer impacts of having TOU periods being frequently updated. Striking that right balance between knowing that there are changes that are happening on the Grid, but you need to give the customer some certainty in terms of what their rate design is, especially when they're making DER investments.

And then guidelines -- yes?

MR. CASEY: Sorry to interrupt, on that TOU period to align with the duck curve, when you see that actually taking effect with the GRCs that get filed to you? Because we're not seeing it today, correct?

MR. BAKER: Well, it's happening now. Yeah, when I get to some of these other updates, I think you'll begin to see that some of this is already starting to flow through. Yeah.

Another piece of guidance was that the Commission expected the utilities in their GRC filings to come forward with a menu of TOU options. And so really looking for a whole spectrum of TOU rate designs to be available to the customer in terms of simplicity. In terms of the peak to off peak price differential. In terms of the number of seasons, including more complex rate designs that would include things such as super off-peak time periods perhaps in a fourth season, such as during the springtime. And so we're starting to see some of that play through. And I'll get to that in just a little bit.

The second ongoing activity has to do with the push towards residential default time of use, which the Commission set forth the vision in 2015 in its Rate Form Decision. And we've made some accomplishments with regard to implementing opt in TOU pilots that are ongoing now. And will be continuing through the end of this year. We're starting to get some data and we'll be getting more data as that continues.

There are also default TOU pilots that have been now approved or there's one pending approval before the Commission. Those will be implemented in 2018 and this is all part of our preparation to default residential customers to time of use in 2019.

Within the general rate cases there's a series of actions as well. And one significant development is the San Diego GRC Phase II Proposed Decision, in which the Commission or I should say the ALJ has proposed approving a shift in the TOU period to 3:00 to 9:00 for all customer rate classes. And so that's a significant step forward.

Previously there had been a decision, I believe it was back in 2014, where one opt-in residential rate for Southern California Edison was approved to go to a late-shifted peak. I forget what it was exactly, 4:00 to 9:00, maybe. And so this is a pretty significant step forward.

There's also major changes in this decision with regard to demand charges. And the ALJ proposes to shift towards less collection of demand charges through non-coincident peak and more towards peak. So that with the use of storage technologies and what have you, some of those demand charges could be more avoidable with DERs.

And we now also have a pending GRC for Pacific Gas & Electric, which has many of these same issues that are now scoped. Next slide, please.

So there's a whole action set related to rate designs to absorb renewables. And the first has to do with these residential opt-in TOU pilots that I mentioned. And within that process each of the utilities are testing three different rate designs. And PG&E and Edison, their rate three actually looks -- they're testing a rate design which has a super off-peak rate.

And in Edison's case there's actually a pretty steep peak to off-peak price differential there. So we'll be learning a lot in terms of how the residential customer base on an opt-in bases responds to those rates. And that'll be really important, because we have a data gap right now. Nationally, there's never been any studies on what the demand elasticity is in shoulder seasons. And also during some of these other hours that are going into the evening hours as well.

As I mentioned, the San Diego GRC Phase II PD is now before the Commission. And it does adopt, had adopted a daytime super off-peak period during the weekdays from March to April for the hours of 10:00 to 2:00. So that's specifically targeting that period of time when there is excess renewables on the Grid.

There's also a demand charge exemption wait option, which is provided also during that same peak period window as well. So that's trying to get some of the non-residential customer base to be able to begin to take up some of that excess renewables through some kind of load shifting patterns.

There's -- did you have any follow-up questions on that, Keith?

MR. CASEY: Are those San Diego rates? These are opt-in rates as well or?

MR. BAKER: No. Those are --

MR. CASEY: These are default?

MR. BAKER: Yeah, those are across-the-board changes.

All right. So moving on to the net energy metering successor, there's an action to specifically be implementing the Disadvantaged Community Alternative, which is required pursuant to AB 327. And the record has now been formed in that proceeding and the Commission is turning toward issuing a proposed decision, probably sometime this year.

And then finally, I mentioned earlier one of the tougher and more important challenges is we call this colloquially the NEM knot. But it's sort of like this Gordian knot of how do you get the value right for NEM with multiple different value streams? And there's a goal in the Action Plan to ensure that the analytical support activities are available by 2019 when the Commission revisits NEM.

And that work is ongoing in the DRP, where the locational net benefits analysis methods, which Gabe will speak about next, are under development in that proceeding.

Any further questions?

MS. BROOK: This is Martha. I have just one, maybe it's a weird question, but since that super off-peak matinee price pilot or it's not a pilot. It's across the board and it's only for two months. Is there a commensurate like education and outreach part that the utilities are mandated to do? Otherwise it's like people are going to blink and that time period is over, right? So how do you expect to change behavior for two months, I guess is the biggest question?

And so is it just a rate and you've got to figure it out for yourself? Or is this going to be a campaign across the state or at least in Southern California that helps people understand the value of that?

MR. BAKER: That's a really good question. Is there a representative from San Diego Gas & Electric that can speak to that? I personally don't know, but you make a good point.

CHAIRMAN WEISENMILLER: I was going to say I'm sure Martha can double check with their rep and maybe they can submit something for the docket here on that question?

MR. PETLIN: All right. Well, good morning Commissioners. I'm Gabe Petlin a Supervisor in Grid Planning and Reliability at the Energy Division of the CPUC. Thank you for the invitation to speak here today.

I'm going to cover the first three bullets in the agenda are all under the Distribution Resource Planning Proceeding. And the last bullet is the Smart Inverter Implementation Update, so these are effectively two presentations. In the interest of time I think I'll emphasize on the Distribution Resource Planning presentation. And if there's time, we can get into the smart inverters unless you prefer a different order.

So what I'm going to present on is a vision and overview and status of our CPUC Distribution Resource Planning Proceeding as well as Smart Inverter Implementation. Distribution Resource Planning is a very exciting and potentially game-changing proceeding, which brings new tools, analytic approaches and investment frameworks into distribution resource planning to enhance the role of distributed energy resources to provide both important reliability and grid services, but also provide ratepayer benefits. Next slide, please.

So the origins of the Distribution Resource Planning Proceeding come from the landmark AB 327 legislation in 2013, which added several sections of code to the PU Code. And these are paraphrased as first defining distributed energy resources as energy efficiency, demand response, renewable DG, storage and electric vehicles. And directing the investor owned utilities to file distribution resource planning proposals that would identify optimal locations for deployment of DERs.

And that in reviewing and approving these plans, the CPUC and the utilities should seek to minimize overall system costs and maximize ratepayer benefits from investments in both grid infrastructure as well as DERs.

And where the utilities propose any spending on distribution infrastructure needed to accommodate higher penetrations of DERs, we should be applying the test of realizing net ratepayer benefits as well as just and reasonable standards that we traditionally apply in the GRC context. Next slide, please.

In addition to those statutory requirements, President Picker, in his 2015 guidance ruling on the DRP applications established effectively these vision elements for the DRP proceeding that can be best summed up as creating a plug-and-play distribution grid for distributed energy resources. With these three goals of modernizing the electric distribution system to accommodate two-way flows of energy and enabling services throughout the IOU networks.

But also enabling customer choice of new technologies and services that both reduce emissions and improve reliability in a cost-effective manner. And also animating opportunities for distributed energy resources to realize benefits through the provision of grid services. Next slide.

So as the PUC set out to implement these new code requirements we made the decision to structure these requirements into two sister parallel proceedings, which are very closely coordinated, but they are separate dockets. And so one that I help oversee is the

Distribution of Resource Planning Proceeding. And other is the Integrated Distributed Energy Resource Proceeding. And so this slide attempts to help you understand how these two sister proceedings are divvying up the goals of the DRP.

So the DRP is focused on evaluating locational benefits and costs of DERs. And the IDR proceeding is primarily concerned with the sourcing of DERs in those optimal locations identified through the DRP. And so that includes the development of standards, tariffs and potentially new rates that address DERs and the incentives. And so the DRPs also focused on reviewing utility spending proposals necessary to integrate distributed energy resources. So at a very high level, that's how the two proceedings are working very closely together. Next slide, please.

So how the DRP Proceeding is structured is in three tracks. And I'm going to focus today a little bit on Track 1 and Track 3. Track 1 is primarily concerned with new tools, methodological issues including integration capacity analysis and locational benefits analysis. And Track 3 is primarily concerned with new policy issues and process alignment issues, including growth and load forecasting of DERs, grid modernization and distribution investment deferral. Next slide, please.

So for all those issues I mentioned I'm going to go into a little more detail now. So the first new key analytic tool for the Distribution Resource Plan is integration capacity analysis. What this is, is the utilities implementing a method of calculating all available circuit hosting capacity to accommodate additional DRs without grid upgrades. And then publishing these results in an online heat map and data base that is regularly updated and publicly available.

And so the three primary use cases of this integration capacity analysis is to help identify for DER developers the grid locations where DERs can interconnect without system upgrades. And then to help inform the PUC to streamline, potentially even automate the Rule 21 interconnection process to make it more efficient. And then to also continue inform annual distribution planning.

So for example if it identifies proactively where grid upgrades are needed on a proactive basis to accommodate expected autonomous DER growth, as opposed to waiting the DERs to come apply through the Rule 21 process.

And the status is that we expect to have full system roll-out of ICA by the second half of next year. The utilities have implemented this on a pilot basis in two distribution planning areas. And then by next year, it's going to be fully rolled out. Next slide, please.

So the next major analytic tool in DRP is

Location Net Benefit Analysis, which is trying to determine optimal locations for DER deployment based on the opportunity for DERs to cost effectively defer or avoid traditional distribution and transmission system investments. So the results are going to be published, again, in an online LNBA tool and circuit heat map of value on the Grid of avoided cost. And inform candidate DER deferral opportunities for competitive solicitation processes, which are being first piloted in the IDR Proceeding, but will then eventually become an annual process through the DRP.

And it could also help inform some of the new rates and tariffs and a future NEM 3.0 policy, as Simon already mentioned in his presentation.

And the status here is we also are expecting a full system rollout by the middle of next year. We also did a pilot this with the utilities in two distribution planning areas thus far. Next slide.

And finally, another important tool in the Distribution Planning Proceeding is DER growth and load forecasting. And this is not quite as new as the other ones, because as the CEC is well aware, there is an annual IEPR load and DER forecast on an annual basis. But the challenge for the DRP is to take a statewide forecast and disaggregate it down to a very granular level at the distribution circuit level, so that we can better inform distribution planning.

And this is a key input into the DRP, because once we have a growth scenario forecasted, then this can inform the integrated capacity analysis as well as LNBA determination of optimal DR locations. And it can help inform distribution deferral opportunities, so it really requires some important process alignment between the IEPR, between --

CHAIRMAN WEISENMILLER: I would just note that President Picker asked me a couple of years ago that we really do more disaggregation in the forecast, so it could be the bases for your distribution planning. That's why we've had this huge effort on disaggregating and more granularity on demand forecast.

MR. PETLIN: Certainly, and then all the needs to have this aligned between IOU methods IEPR methods, IRP as well as LTTP. So next slide, please.

So some of the key agency alignment issues around adoption of DRP growth scenarios is that, as I said DRPs primarily concerned with how do you take a forecast and disaggregate it down to the circuit level to inform distribution planning? Each year there's going to be a growth scenario adopted in the DRP to inform the annual ongoing distribution planning and how do we best align the timing of that?

So there are, for example, in the 2017 proposed growth scenario by the utilities, some differences. These are 2017 --

CHAIRMAN WEISENMILLER: But I think President Picker wants the utilities to use the Energy Commission's adopted forecast as does the Legislature, so keep that in mind.

MR. PETLIN: We certainly will. What I'm trying illuminate here is that we're encountering timing challenges, where information could be --

CHAIRMAN WEISENMILLER: We're having enormous challenges disaggregating, frankly. So when you get to the -- we've always done some degree of disaggregation, but the question is how do you make that public and transparent and which needs data?

MR. PETLIN: Right.

CHAIRMAN WEISENMILLER: So I'm just saying you do not want to go to the Legislature and explain why you're using a different forecast than we are, that we've adopted.

MR. PETLIN: Yes, so we're encountering some challenges in the timing difference between when an IEPR forecast is available and when it actually gets put into place to inform actual investments on the ground. And while we would like to align with the IEPR forecast, that's our intent, the question is how to do that and still have accurate forecasts of distribution planning.

CHAIRMAN WEISENMILLER: Thank you. And I've certainly talked to President Picker about that a lot. I'm sure we'll continue to talk and I'm sure we will stay consistent. And there are times that you would have to deal with the realities of what is a reasonable forecast and how to develop a new transparent process, as opposed to what's the latest one that someone pops out.

MR. PETLIN: Thank you. Next slide please.

So just to give you an idea of a timeline of DRP growth scenario development in June, in fact yesterday the utilities filed their updated assumption and framework documents proposing their growth scenario methodology for the 2018. This would be -- it's a 2017 growth scenario that informs the 2017-2018 planning cycle.

So there's a July comment period, a key opportunity for agency input on alignment, and then expected ruling later in July. And then that will cover the 2017 growth scenario.

The 2018 growth scenario will be worked out in a decision later in this year. And again, it will be a key input opportunity when that process kicks off in the fall.

But the idea is that the IOUs will produce growth scenarios each year based on the guidance. And that will inform the distribution planning on an ongoing basis. And the goal is to have this as aligned as possible with all the different state agency planning processes underway. Next slide.

So another key output of the distribution resource planning process is distribution investment deferral. So this is really one of the most important elements of DRP, is where the value comes of identifying candidate-planned distribution investments. And deferring them through non-wires alternatives through sourcing of DERs that meet the same reliability and grid needs at a lower cost. And this is a -- we expect a staff proposal any day now to come out on this. And the first year this is being piloted in the IDR Proceeding and we expect a solicitation process this fall for the first group of deferral candidate projects, but by next year we expect this to be an ongoing and regular process that will occur every year. Next slide, please.

So some of the key elements of the distribution deferral framework are envisioned as an annual grid needs assessment that the IOUs will produce. A stakeholder process that we're proposing as the Distribution Planning Advisory Group to help vet the candidate deferral opportunities. And then a competitive solicitation that will result in procurement of DERs. Next slide, please.

And then finally, one of our last frameworks, from our longer-term framework is grid modernization investment. As we move toward a higher penetration world of DERs, the need for new advanced technology to help manage the Grid and to help integrate the resources to help with sensing management, switching. It requires a new set of technologies that haven't traditionally been deployed, but also raises new questions about the appropriate cost and reasonableness of these technologies.

And so what we're doing in this track is developing some model guidance to help inform the GRC process, where rate funding gets approved. So that that process can have a much better basis on which to evaluate these proposals for new investments and new technologies. We want to avoid the possibility of what we call gold-plating the grid, over investing in technologies that are not needed, but at the same time make sure we understand what's really going to produce value for ratepayers, in terms of new technologies.

So we have already issued a staff proposal on grid modernization and the comment period is underway. So you can expect by the fourth quarter of this year a decision from the PUC adopting hopefully some guidance around grid modernization in the DRP. Next slide, please.

So I won't read you the candidate. This is just a draft definition of grid modernization from our paper, because it could be revised through the comment process, but just to give you an idea that it's there. It's primarily about which parts of these concentric circles are we talking about? Are we talking about primarily technologies that enable DER-related investments, or are we talking about traditional safety and reliability. And then the overlap where you achieve all three of those goals. Next slide, please.

So that's the end of the DRP portion of the presentation. I do have some slides on the Smart Inverter Implementation Plan and I'm happy to continue or save it for after lunch or if we're just short on time.

CHAIRMAN WEISENMILLER: So if I were to give you five minutes, could you cover it?

MR. PETLIN: Yeah, I could condense.

CHAIRMAN WEISENMILLER: Then why don't you do that? Yeah.

MR. PETLIN: Okay.

CHAIRMAN WEISENMILLER: We're going to squeeze the lunch a little bit to get back on schedule.

MR. PETLIN: Okay. So as part of the Rule 21 Interconnection Docket, we have a track to develop technical standards for implementing smart inverter capabilities into the interconnection process. Next slide, please.

So just at a very high level, a smart inverter, what is it trying to solve? It helps to mitigate many of the traditional concerns associated with variable DER generation, enables greater penetration of DERs and enhances DER value by enabling grid services. Next slide, please.

And a smart inverter does more than what a traditional inverter does, which is to convert DC to AC power by enabling autonomous response to grid conditions, bidirectional communication for monitoring and control, and advanced functionality for DER dispatch. Next slide, please.

So I think I've mentioned these benefits. What I wanted to go to the next slide is to give you an idea of the implementation plan, so next slide.

So here, you can see how the smart inverter work is organized around three phases of functionality. And this has been a lot of coordination with the CEC and thanks for your support. We've had a technical consultant who's been very instrumental in helping to facilitate a technical working group that's been working for years to develop these standards.

So in Phase 1, what we call autonomous functions, these are functions that will be always on not and subject to control. They will just simply improve the function of DERs on the Grid and they are actually going to be mandatory as of September this year. Any new DER getting permission to operate on the Grid, interconnecting through Rule 21 will be required to have a certified smart inverter with the autonomous function capability.

The next phase is the advanced communications to enable more advanced functionality. And we expect that this will become required. It'll be either the later of March 2018, or nine months following a test standard. So the working group has developed this recommendation and it has been adopted into Rule 21.

And then we're several weeks away. Later this summer, we expect to see the investor owned utilities file their proposed tariff revisions for the advanced functions, which are really the ones that involve two-way communication and different control settings. And can be more responsive to grid conditions. And we expect a similar late 2019 at the latest, functionality of those standards, also tied to a certification standard and very much coordinated with IEEE standards on smart inverters.

So there's a lot more slides I could cover, but I think that kind of gives you a very quick overview of where we are.

CHAIRMAN WEISENMILLER: Yeah, that's good, so one comment and one question. So back when you talked about basically advanced technologies for the Grid, it would be useful to get your needs into the Microgrid Roadmap development and also the summer research planning.

And the other thing I wanted to say on the inverters, do the requirements for smarter inverters apply for replacement inverters of someone who's been interconnected before?

MR. PETLIN: Yeah, that's a great question. We're currently looking at that right now. I don't have the outcome, but we are looking at what we're calling end-of-life inverters.

So for example, some inverters are under warranty and so the supplier may not be required to go to a smart inverter. But if it is at the end of life, that's another question and so we're looking at that right now. I expect that we would be trying to get some relatively quick decision on that pretty soon, because we don't want to lose the opportunity to upgrade to smart inverters where traditional inverters are failing or just being replaced. But we're actively looking at that right now.

CHAIRMAN WEISENMILLER: Yeah, and that's important right now. I've talked to different solar companies who have said that they -- in other states they use smart all the time. In California, where it wasn't that they're doing a replacement it's not necessarily smart. So unless you require it, you're probably not going to get it.

MR. PETLIN: Yeah. I agree that that's definitely an opportunity that we should try to make sure we don't miss.

CHAIRMAN WEISENMILLER: Great, okay. All right, so thank you.

So let's do lunch. Let's get back by 1:00

(Off the record at 12:09 p.m.)

(On the record at 1:06 p.m.)

MS. RAITT: We'll resume our workshop on Integrated Distributed Energy Resources, integrating them into the California Grid. And so our panel is on Transmission and Distribution DER Activities and Tom Flynn from the Energy Commission is the moderator.

MR. FLYNN: Thank you, Heather.

Good afternoon, Chairman Weisenmiller and others on the dais. I'm Tom Flynn, a Senior Electrical Engineer in the CEC's Transmission Planning and Corridor Designation Office. Given that DERs or DER in general uses both the transmission and distribution systems, this next panel is going take a look at DER from that perspective, from the perspective of the transmission and distribution systems.

This panel will discuss the challenges as well as the opportunities that DER presents to transmission and distribution operations and planning. Our first panel member is Delphine Hou. She's a Manager of State Regulatory Relations at the CAISO. She's going to discuss DER in the wholesale market, what the ISO has accomplished thus far to facilitate the participation of DER in the wholesale and what work remains and what the next steps are on that going forward.

Our second panelist is Mark Esguerra. He's a Director of Integrated Grid Planning, Grid Integration and Innovation at PG&E. And I think he's also, and you can correct me if I'm wrong, here on behalf of More Than Smart as well to present some very interesting work that More Than Smart has been doing in the area of real-time operations. And discuss how the desire of DER to maximize the use of their assets is driving operational challenges on both the distribution system and the transmission systems. And is exposing the need for coordination, operational coordination between those two systems. And I'll add that that's coordination that up to this point hasn't needed to exist. And didn't exist and has been identified as something that needs to be established and put into place.

And our third panelist is Jeff Billinton. He's the manager of Regional Transmission North at the CAISO.

And Jeff's going to focus on transmission planning and discuss both the challenges and opportunities that DER presents for both transmission reliability concerns and future transmission needs.

So Delphine, you can begin.

MS. HOU: Thank you, Tom. I'm back. Don't worry, I don't have another presentation after this. I'm here to present the models that exist in the California ISO as of today. And I want to talk a little bit more about how even that has evolved.

So the earlier models are focused on demand response and that's our proxy demand response as well as our reliability demand response resources. I think I mentioned in my earlier presentation this morning, is the vast majority of the megawatts that we have in the ISO market today are the reliability and they're triggered on a warning.

So that's about 1,300 megawatts in our market, but what we're seeing is that a growing number of megawatts, especially coming through the CPUC's demand response auction mechanism is going to be focused in the proxy demand response bucket. And so today I think the most recent numbers I have is just shy of 200 megawatts, but we do expect those to grow.

Our third model is the non-generator resource model. And that one we developed more specifically for storage resources, because of its unique capability to charge and discharge, so consume and produce energy. So we wanted to have a different model to represent their capabilities and we continue to refine those.

And you can imagine that that's the kind of model that could be a good fit, not only for large stationary storage, but as Noel was talking about maybe in the future looking at vehicle-to-grid integration maybe there is some scope there for that usage.

And the very last model is our DER, the Distributed Energy Resource Provider. So that is actually a great model to end on, because as you look at these models it really shows you the evolution of CAISO's thinking as we work with stakeholders. So we started off with a sort of you have DR, we will create a model for demand response. But now I think we've evolved to a point where we're saying, well now you can have an aggregation of different kinds of distributed energy resources.

Within that aggregation you could have solar panels, you could have storage, you could have a number of things in there. And that actually provides from the feedback we've gotten, a lot more flexibility to stakeholders in order to be more creative and provide services rather than being pegged to necessarily being labeled as this resource is a DR provider. Therefore it needs to use the DR model.

But after even creating the DER provider we're still finding even more ways in which our older models are still evolving. So as I mentioned earlier this morning, there's a significant amount of interest from storage providers to become proxy demand resources. And we think that's very interesting as well, so if they're able to use that model effectively then that is an avenue for them to pursue. Or they can be NGR or they can be part of a DER provider.

So let me talk a little bit more about the DER provider in the context of being the first ISO in the nation to really have this structure, to really recognize that if DERs participate it will be an aggregation of probably different kinds of resources. And so right now we have the tariff process already approved, as Noel mentioned earlier this morning. And we have I think at least four aggregators that are interested in applying for this, but also this model requires a relationship with the distribution utility as well.

So I think that's another part of the discussion and as I move into the initiatives I want to talk about, I wanted to also relate back to the work that we're doing with the PUC in terms of working out a lot of the regulatory questions, potential barriers that both agencies can work together to sort out. So let me move on to the next slide.

So the way CAISO approaches a lot of these models is through a stakeholder initiative. So we get the stakeholders together to talk about what is needed in terms of market design changes and improvements. So we've had a series of stakeholder initiatives, which are not listed here. But they're more technical and they were sort of the simplification of metering and telemetry requirements that actually were part of the DR and the Energy Efficiency Roadmap.

So now that that sort of groundwork has been done in terms of simplifying ways for smaller resources to participate in the market, both of these initiatives -- the Energy Storage and DER initiatives Phase 1 and 2 and every soon Phase 3, is sort of the evolution of that. So now we've come to a point where we have some basic groundwork laid out, but we want to think about well what's the next step in removing barriers for DER participation?

So I won't go through every sub-bullet. But you'll see the sub-bullets listed there is a mix of technical as well as sort of higher level regulatory or market design changes. So I'll give you an example, enhancement's the non-generator resource model. There we found sort of a very technical issue that we needed to attract the state of charge of batteries. So that was a very technical fix that stakeholders really rallied around and said that would be a great improvement for our resources to operate in the market.

On the other hand, the last sub-bullet point under Phase 1 is clarification to rules for non-RA multiple-use applications. There you get into a lot more complicated discussion about how agencies work together, what does it mean to be resource adequacy? And that actually was a springboard for us to start discussing the multiple-use applications that Rachel talked about in the storage proceeding. So you can see that from these initiatives it is very much based on stakeholders coming together. They rank priorities, but also it's a compromise of looking at the industry and what are the low-hanging fruit issues we can address immediately. But what are the bigger picture issues that we really need to start rallying around and discussing?

And so out of the first phase of ESDER is where we started coordinating with the PUC to talk about well what are the multiple-use applications? So just as a footnote, when Rachel talks about the multiple-use applications in the storage proceeding at the PUC the companion at the ISO is ESDER. So that's where we've been housing that discussion.

So we moved on to Phase 2, so what we like to do is if we get a suite of market-design changes or fixes that we think are good to go we can take that to our Board of Governors and take that to FERC. We want to close that out and move those along, so we've opened up a second phase, which we're at the end of that we will close out very soon. A big issue under Phase 2 is sort of the more engaged effort on multiple-use applications. There wasn't a lot for the CAISO to enact on that, but there was a lot of discussion at the PUC. So we're looking forward to the Storage Proceeding decision that comes out of that proceeding.

But here again, it's a combination of technical changes that the stakeholders can rally around. But also longer term discussions about how we want our models or how we want the markets and the regulatory rules to evolve in order to accommodate and remove barriers for the DERs.

With that I'll close.

MR. FLYNN: Any questions for Delphine?

(No audible response.)

Okay. Next up is Mark Esguerra from PG&E who's going to talk about the need for operational coordination at the transmission distribution interface.

MR. ESGUERRA: Thank you, Tom. And thank you

Delphine, and good afternoon.

So what I'm going to go over is work that was performed with More Than Smart, the California ISO and the three utilities in California. And essentially, we've put together some work in terms and summarize it in the form of a white paper, a coordination of transmission and distribution operations in a high electric resource grid. Next slide.

And so when we start to think about this space, we did want to provide some context. And so a lot of folks here are familiar with the changing power mix in California. What we're seeing with potentially moving to a higher penetration of DER market is potentially less reliance on this utility scale generation. And an increased reliance on distributed energy resources.

This shows up in many of the different proceedings that are going on at the PUC. We heard a little update on smart inverters and a lot of the functionality that's being proposed and be implemented would be to help provide more support on to the Grid.

There's also the look for additional electric vehicles and so more adoption in the Grid is becoming more decentralized. And what we're seeing here is there's a lot of opportunity for DER owners that are interested in maximizing a lot of these opportunities in terms of providing multiple services to multiple entities in the ISO, the distribution companies, as well as the end-use customers. Next slide.

And so Delphine touched on some of this here and I'll touch a little more, because it comes into play in my conversation here about this. But there's a lot of efforts going on in terms of lowering barriers for DERs. At the PUC there's initiatives on developing non-wires alternatives. And the process for that as well as the multiple-use applications as Delphine touched on earlier.

And with the ISO there's a lot of work going on in terms of distributed energy resources, particularly the DER provider tariff. There was work performed where the ISO worked with stakeholders to develop this platform. In March of last year, they filed a tariff with FERC, essentially identifying that there's an opportunity for aggregations of half a megawatt or greater to participate in the ISO's energy and ancillary services market. FERC approved the platform in June of 2016. Next slide.

And so when the utilities got together working with More Than Smart and the ISO, we started discussing what are some of the operational challenges that we would face under this high DER penetration world, particularly these DERs providing services to the ISO market. And so currently, what we're seeing is a lot of these dispatches that the ISO would be looking towards for DERs, they would not necessarily would know the impact or if they were feasible on the distribution system. And currently, there isn't very robust methods of forecasting how these DERs are actually going to impact the net load at particularly what we're defining is at the transmission and distribution interface.

The other operational item that the distribution companies are pointing out is that in terms of the visibility and control and situation awareness of a lot of these DERs that are behind-the-meter, we don't have the same level as the ISO does on transmission-connected generators. And so what we're finding is that as penetration increases and as participation in these markets increase, that the challenges will only increase. And so we're finding out there's more need for a coordination at the transmission and distribution interface. Next slide.

And so when we look at this here, DERs, they use both the T-D systems. And specifically, they're using both the transmission and distributions systems if they're participating in the ISO market, or they're operating autonomously and making sales to the end user or providing services to the distribution company. But it's important to point out, and this white paper gets into, that there are differences on the transmission and distribution grid.

They're designed differently. They actually serve different functions.

And what we're defining here for the parties to review is that the T-D interfaces we're defining as the substations that connect transmission and distribution where historically, power typically flowed from one direction from transmission down to the end users. And when we're seeing higher months of penetration, particularly with these DERs responding to signals, you can start to see the power flow in different direction, which will cause challenges for operating and planning. Next slide.

And so this slide here is just to kind of discuss and provide a picture of what a local transmission system will look like. And essentially the familiarity with this is that the transmission systems are designed as a more of a mesh network to transmit bulk power from generation to distribution substations, typically from cities to counties, counties to counties, and vice versa here. Next slide.

When you layer on the distribution system with the complexity you can see that there's a lot more going on underneath that transmission system. Although the distribution system is radial in nature, there's a lot of distribution equipment out in the field. And it requires different levels of review when you do the planning, different granular levels of review. You know, not just what's going on at the substation, what's going on at the head of the feeder, but there's different connections, different tap lines that can feed customers. And DERs can cause different types of behavior on there and so how do you capture that when you start thinking about these opportunities for DERs? Next slide.

And so what the paper gets into, it talks about some of the situations that the utilities need to think more about as well as others, more to educate folks. And the differences between T-D in terms of the availability, so there's the distribution system tends to experience more outages. It has a lot more exposure to these outages. As we mentioned they are radial in design, however when you really look at the distribution system they have many connections to other feeders. And so although it's radial in nature there could be different types of combinations of switching that can change the topology of the distribution circuit.

And these outages will create what we'll call an abnormal configuration and these abnormal configurations, depending on DERs and how they're connected, if they're aggregated could create different constraints on the distribution side, which could affect the DERs ability to participate in the ISO's market. Next slide.

The other item here, and I think we've heard some of it, is forecasting. You know, forecasting more from the short-term perspective and the impact that these DERs on gross and net load. And so the ISO and the distribution companies, we need accurate short-term forecast to better operate reliably and for the ISO to be able to run the real-time wholesale market. Most of the DERs today behind-the-meter do not participate in these markets as supply resources, but more as load modifiers, which again alter the load shape.

And so the point here is that the ISO and the distribution companies, we tend to have less certainty about whether there's going to be sufficient resources available to serve load, because of this changing amount. This could lead to over-commitment of different supply resources. Next slide.

Another item here is just the lack of visibility, situational awareness, and control. The distribution operator and the ISO do not have the same visibility situational awareness with a lot of these DERs that are behind-the-meter. I mean, there's pilots that we're visiting to take a closer look at and a lot of the visibility we have is more on a net basis. But it's not there today.

The DERs themselves, they don't have the visibility on the distribution system to understand are they going to be impacted, right? And the DOs, the distribution companies, need better visibility into their own system so that they can better predict the DERs behavior. The real-time effects on what these DERs are doing to the Grid, as well as to be able to better forecast. Next slide.

And then finally, this gets into more of the distribution design itself. Just the distribution system may have phase balancing and voltage regulation issues, so balancing loads between the different phases can become more challenging as you get higher and higher penetration. Particularly if they're aggregated and responding to signals in a different behavior than we originally had intended them to.

So you must consider what those effects are and how it affects the system. So we definitely see that there's opportunities to take a closer look in the planning perspective of how do you capture this? You know, can we understand how these systems are going to interconnect? What phases are going to interconnect? So obviously there'll be a lot more review of the planning process in being able to capture that. So next slide.

So how does it work today in terms of

coordination between the transmission and distribution operator? And what we have here is just more illustrative of how it works for demand response today. Essentially, on this chart you'll have utility demand response and non-utility demand response here on the diagram. The ISO will issue a signal to dispatch. Today the ISO communicates with the utility transmission operator for that.

And one insight that we've identified is that the ISO and the distribution operator, today they do not coordinate. They do not actually talk. This communication occurs with the transmission operator. And so that's something there that we want to consider is are there other methods, or other opportunities of how this information can flow? Next slide.

And so when we looked at the work that we've prepared here under this white paper the questions were being asked like, what are the new coordination activities? Do we believe or need it? And so we felt that it was really important to distinguish the time of this, because we can talk about how we want this all to look way out into the future. But we also are looking at implementation of the tariff today. So we wanted to consider two timeframes: you know, more of a near-term look like what's happening now as well as a mid-term. And eventually a further, longer-term outlook, which gets into other consideration.

And so whereas we looked at that we thought of different scenarios to help frame our thinking. And those scenarios are essentially today if you have a single DER that's participating in the market, what does the coordination framework look like? The other condition here is you have a single DER that it's not providing services to the ISO, but is providing services to the utility.

And then the last item here is gets more into the multiple-use application. So you have a DER provider that's actually looking to provide both services. Next slide.

And so when we were going through this analysis we also wanted to make sure we kept this is mind about the multiple use aspect. And how DERs are really seeking to provide these services and earn revenues at multiple system levels. And so when we thought about this we wanted to make sure we understood from a behind-the-meter perspective what are the different services that they were looking at there: time of day load shifting, demand charge management, service resiliency.

And then from a utility perspective, what are the distribution services? This gets into the non-wires alternative, the deferral of new infrastructure. And some of these services are distribution capacity relief, voltage management, power quality. And then moving down at the wholesale side, the transmission side, wholesale market participation, resources adequacy. And as well as potentially serving as non-wires alternative for transmission. So the vehicles to do that, would be in some form of bilateral contracts with the DOs and the load-serving entities. Next slide.

And so the objectives of each of the entities and responsibilities drive different tools, information flows and procedures. And what we've summarized here is the ISO's primary DR concern at the T-D interface is more predictability. Being able to have confidence that if they're going to send a dispatch signal to these DER providers what they're going to get and their confidence that they will get it. As well as being able to better forecast from a short-term perspective on what they're going to see at the T-D interface.

And then also information to inform their planning efforts, more on the long-term side. What type of DER growth are they expecting? So this starts to weave in a lot of the work that we were talking in the earlier panels about, continued with the coordination with the IEPR, the IRP, the TPP and the DPP. You know, really ensuring that we have good coordination with the forecast and that we're all aligning from a similar set of assumptions.

From the distribution company the concerns are largely with reliability. We want to make sure that with DERs participating in the market that we're still providing safe reliable service and affordable service to our customers. Part of that is really having good visibility into what the DERs are actually performing. As well as being able to have the ability, if there is going to be something that's going to impact reliability at least the ability to modify or at least address some of those behaviors from the DER.

And then similar to the point I mention on planning, the long-term look for DER growth. You know, making sure that we are factoring that in our distribution and transmission planning. For the DER provider and the aggregator, they're really concerned about ensuring they have a good business model. So their ability to participate in essentially all markets that they're required. That they have the required performance capabilities as well as their ability to optimize their choice of their market optimization and manage the risks. So those are some of the key things that we wanted to draw out. Next slide.

And so finally it's a close, so there's near-term recommendations that we've identified here. And a lot of these here are really looking at piloting and some of these methods. One of them is the distribution operator should be able to communicate advisory information about their distribution grid to DER providers. So that they have better awareness about what they're capable of providing to the ISO market. So this would allow them to modify their bids.

The ISO should provide day-ahead DER schedules to the DO. So this will allow the distribution operators to be able to take that information and really look to try to pilot developing processes to assess the feasibility of those dispatch. And the complexity is, as we mentioned in my previous slides, a distribution grid can go through numerous switching configurations based on planned maintenance and forced outages. So being able to have some of that upfront information to be able to plan ahead would greatly help.

And the DER provider, as well should be able to communicate its constraints on its resources as well. You know, based on feedback and issues that they may have on their end or information from the distribution operator, would be able to communicate that back to the ISO.

And in closing, one other item here that we've identified is that when we look at this there was one area that we felt we wanted to fill in terms of an opportunity. That there should be some sort of agreement between the distribution company and the DER providers. We've coined it as an integration agreement, so a lot of these DERs already have an individual interconnection agreement with their utilities.

However, when they operate in aggregate they may operate slightly differently. And so really having an integration agreement that really sets out the rolls, responsibilities and obligations between the DER provider and the utility, we felt was something that could help further improve this process.

So I'll paus there, so Tom?

MR. FLYNN: Thank you, Mark.

Any questions for Mark from the dais?

CHAIRMAN WEISENMILLER: Yeah, a couple of questions, one of them is trying to -- obviously this is a transformation about how the distribution system has been designed, built and operated. What are the three major things, again trying to keep it simple that really needs to be done with your infrastructure to enable this type of operation?

MR. ESGUERRA: Yeah, that's a really good question. Before I get into infrastructure, I was thinking about your questions when you posed it earlier. And I think one of the more immediate items here is really fleshing out these coordination procedures between the transmission and distribution operator.

Today we have very limited amounts and it's manageable through manual processes. In the future, as far as infrastructure it one, will have to develop the coordination procedures. But from the infrastructure perspective if we ever get to a point where there's very, very high penetrations of DERs participating in markets that are deep into the distribution grid with multiple aggregators, I can see that in order to communicate a lot of this advisory information there would have to be some sort of infrastructure, IT, software design setup on the distribution side, to be able to assess the availability of distribution feeder. And to be able to make some of that information available. So I think from that perspective.

But as building up to that, I think the utilities would say that we would need a lot more ability for adding additional visibility and control. And there's work that we're doing in terms of piloting some of this work. One of the areas that PG&E is looking at, is in its distribution energy resource management system, we're piloting DERMs. We believe that that can inform us a lot about the ability to visually see what's happening with DERs, have a good forecast, as well as potentially have opportunities for control.

So those are two types of investments that I think that we would be closely looking at. Or essentially it was three: the ability to provide availability of the distribution grid, more visibility in control and potentially some sort of control for aggregated DERs.

CHAIRMAN WEISENMILLER: Yeah, my last question is just certainly when a generator hooks into the transmission system there's a lot of control. You know, the interconnection process goes through a lot and you know, dealing with potentially queues and stuff. And also the communication requirements are pretty stringent.

Now, as you go on the distribution sub-level, particularly interconnecting in communication, again how do we not end up with -- I don't know how many applications you have now for interconnecting to the queue, but I remember there were times it was like 70,000 or something absolutely absurd. And yeah, you obviously had to put in place a queue system to manage that. But again, this has got to be simple on the one hand, but effective on both communication and that. And also dealing with queuing. What have you guys thought about that so far?

MR. ESGUERRA: So, in terms of that this is where if you take a look at what our current practice is for most of the utilities, when it comes to like visibility, telemetry, I believe most of the utilities are very consistent. There is actually a threshold of when it would be required and that threshold was around 1 megawatt.

And what we're seeing here is that you may have multiple units here that are going to be aggregating to get you up to a half a megawatt. And so really looking at how do we think about this when we develop this integration agreement. The last point I mentioned, part of that integration is to spell out working with these DER providers on what type of visibility they have that they can provide to demonstrate that they're meeting the half-a-megawatt requirement.

I think there's still work to be done in that area on better defining it. To not make it overly complicated by not making it too simple that it doesn't provide the right level of visibility. So there's going to be some balance there that we have to work out with stakeholders.

CHAIRMAN WEISENMILLER: Yeah, and again just back to -- I think as people get more and more familiar with where the sweets spots are on your system as opposed to the complicated ones, you would not deal with some queue management process for people trying to find that right spot with high value.

MR. ESGUERRA: Correct.

CHAIRMAN WEISENMILLER: You know, how do you just go through that? And certainly on a transmission side, everything is interconnected in some fashion. So as the queue changed we ended up trying to deal with that issue.

MR. ESGUERRA: Right. So the way we're setting it up right now, at least how we're thinking it through for we do have wholesale distribution interconnections. And the large retail interconnections, and in the large retail interconnections they are all currently queued. So they have a way of managing that. But if there's a huge flood, we've got to reevaluate our process to see are we still effective in that.

For a lot of the behind-the-meter items like net energy metering we've done a lot of work here to try and streamline. And you actually can hear -- you've heard that in the PUC's comments about streamlining the interconnection process. PG&E, right now we're very proud. We have about a three-day turnaround for most of that. But when you start to look at aggregation, it's one thing to interconnect them individually. I think we have pretty good processes on that.

But we also have to start planning out where do we expect the growth to occur? And then this would cross over into the CPUC's world on integration capacity analysis of really identifying what are the potential upgrades that we may want to invest ahead of time if we have a very good understanding that there's high value and there's a lack of capacity. I think some of those items will help streamline the process.

As far as the aggregation piece, I envision that there will be eventually some form of queue if we end up seeing a large influx of them coming in through the utilities.

MR. CASEY: Yeah, I just wanted to commend Mark and the utilities as well as the ISO, but especially the utilities for their collaborative work on this. When we introduced the market concept of distributed resources participating in the wholesale market there was a lot of understandable concern from utilities about how do we make that work? And they really stepped up to the plate. No one forced them to join this collaboration. They did it voluntarily and had been working together to really pragmatically think about the nuts and bolts of how we make this work operationally.

And I think it's a very good example of kind of a bottom up approach to a very complicated problem where other areas like New York, I think have taken more of a top down kind of a moonshot of what we want the end state to be, but no clear indication of how you're really going to get there. So I really applaud this effort

There's obviously a lot more work to be done. We're just scratching the surface in terms of how we're going to make all this work, but I think we have an excellent framework. And I'm glad to see it finally become public now, so we can get other people's perspective on this. But I really think you're on the right direction.

MR. BAKER: Yeah, I just had a big picture question I guess, kind of related to your comment their Keith, which is sort of where is California relative to other states and jurisdictions in terms of examining these issues and learning about these issues?

We know that distributed energy resources do participate in some wholesale markets and eastern markets. So, you know, sort of how out on the cutting edge are we here and what, if anything can we learn from other jurisdictions in their experience?

MS. HOU: Well, actually maybe just a clarification, Simon in terms of DERs did you mean aggregations of DERs or just DERs in general?

MR. BAKER: DERs generally, I understand that this aggregation proposal is something -- it's the first of its kind, correct?

MR. CASEY: Yeah, I was going to say I think we're once again leading the country in terms of advancing this concept. And I think FERC is really looking to the other ISOs and RTOs to come up with similar proposals to enable what we did with our DERP proposal. So once again we'll be on the cutting edge.

MR. FLYNN: Does anyone have anything else to add? Okay. And I just want a last check, any other questions for Mark?

(No audible response.)

Okay. Next up is Jeff Billinton from the ISO whose going to discuss transmission implications of this shift to DER. Jeff?

MR. BILLINTON: Yeah, thank you very much. You can go to the next slide.

So looking at the transmission system comprised of say the 500 components of the 500 components of the 230 kV, which make up the bulk electric system. And the (indiscernible) ties to the outside of California and parts of the 230, 115, 60 and 70 kV, which is really for a lot of the local transmission with the interfaces between the transmission and distribution system as we're looking at it throughout California here. Next slide, please.

So as we're looking and really from the transmission perspective, we've -- with the agencies a lot of coordination. In particular, looking at so that we have from the forecast component the procurement and the transmission planning and alignment. And utilizing the CEC forecast, which has the consumption load as well as the load modifiers. I included within the forecast, which includes the behind-the-meter generation that we've been discussing or components of the DERs as we look at it, as well as the additional achievable energy efficiency.

And then with the supply side with the Utilities Commission with regards to the scenarios and assumptions from the old LTTP and as we move into the IRP, the assumptions for those. And the need and emphasis, and I think it was earlier, of making sure that we stay coordinated with regards to those key assumptions is critical as we move forward.

In particular, with the load forecast, which we use at the next slide, using in terms of the forecast for our planning, using the latest forecast of the IEPR forecast as well as differences between the bulk and electric is primarily just the nature in terms of the uncertainties as we get to the locational issues. And at the location or in the local areas, utilizing the AAEE difference in 1-in-10 load forecast in the next slide, as we move.

One of the things in this, like I say in working collaboratively is as the increase in distributed resources continued to increase, and particularly in the 2015 with the levels significantly increasing as we're working with those. The historical time period of when that peak was occurring as well as what is the output of the distributed generation. At that time we started seeing and working with and in the 2016 update identifying a sensitivity to the baseline forecast to take into account the peak shift where as you increase the distributed generation it shifts then, the peak. Particularly as with regards to it being solar, the peak out to the say 7:00, 8:00 o'clock time period when the solar is decreasing.

And so in the planning cycle, as we're looking at it utilizing the base forecast as our base as well as the sensitivity to assess, so that we're not looking as that level of distributed generation increases, that we're not looking to see projects that potentially could be canceled or not. That are actually needed for that later peak and utilizing it from that aspect.

And with regards to this as well is the work that the CEC is doing with the 2017 for the hourly forecast and the hourly load modifiers will take into this consideration of what is the peak time period. And it is a significant effort in working with that, so that's as we move forward then the sensitivity becomes part of the base as we're moving forward based upon the hourly with respect to those. Next slide.

Now, as we look at it from the system perspective with regards to the duck curve and challenges, as we're looking forward. When (indiscernible) duck curve in terms of the (indiscernible) at a forecasted time period we see in terms of already -- and with the blue bubble that's there -- we've hit lower loads as to the net load, which is really the ISO gross load minus the transmission connected wind and solar. We basically had hit a lower than what was originally envisioned from the duck curve.

One of the contributing factors to that is the increased level of distributed generation that has occurred, or not occurred, has developed on the system as we move forward. We're in the order of around the 6,000 megawatts of installed distributed connected generation, which has an impact. And if we look at the next slide, this is looking at the orange line being what was a gross load in January of 2013 and a profile as we look at it where you had a later peak. When we look in terms of the gray line this the gross load, so the load's really at the transmission and distribution interface in 2017 in January. And you can see in terms of the profile changing where you're starting and you've got a belly kind of on the gross load developing by itself, of what the distribution load or the transmission and distribution interface type load is.

And that's attributed as we look at the distributed generation increasing, as we look in time, and expected to grow. And in some -- as we look at some locational areas in an analysis that we did last year, an example of being the Fresno area, which has had a significant penetration of distributed generation -- we already see the PV peak shift or the peak shift occurring in the Fresno area to the 7:00 o'clock to the 8:00 o'clock at the peak time periods. And we see in terms of a significant belly in the off-peak of just the transmission and distribution loads in that area. And at some of the buses we're getting, or at some of the interfaces, close to where it could be a net zero or a (indiscernible) or a reversal of flows at those locations.

And so those are things as we're looking at in the analysis and -- or as the system and how is the system changing as we plan for the increased growth. The next slide.

As we started -- in last year's transmission planning cycle we started to discretely model the distributed generation based upon the levels that were identified in the IEPR forecast. So we started to model the (indiscernible) distributed generation, the gross load as well as the distributed generation separately to reflect that in our models.

The locational, we've been working with the utilities with regards to the forecast from their DRP as well as in the update of the 2016 IEPR. The granularity as was identified, is working to try to lower or get it in terms of closer to the bus, takes into consideration from the system. But also on a climate zone basis what is the installed amounts and those are helpful to try to work towards where that location is.

And then the output is based upon the case that we're looking at it being a peak or an off-peak. A peak being now looking on the historical or the peak shift, being at the 7:00 o'clock time period or an off-peak being at the middle of the day on a Saturday. Having to look at the profiles of what the distributed generation is with respect to output in relation to the consumption load or the gross load of the system.

And then in terms of working to the issue of when we're modeling on the transmission system we're modeling more of a larger discreet individual generator that you get the characteristics of, working with the modeling of aggregating a whole bunch of small that have different characteristics. And at those levels what is the characteristics of those generators as we aggregate them? And so those are things that we're working with as we go forward.

The next slide shows in terms of the levels based upon the CEC forecast that we're using in our forecast. And as you can see in terms of 2018 an installed of around 6,000 with a growth of that up to around almost 13,000 megawatts of distributed generation being included in our transmission planning models to make sure that we're accounting for in the studies that we're doing.

The next slide reiterates in terms of a point that we'd talked about previously, and like you say the using and making sure of it in terms of our planning, the CEC's forecast is the input of the load forecast. And then getting that down to our busbar level, which is effectively at the station level or the transmission and distribution interface level.

As we are working the CEC's forecast has some granularity in it. As we're looking in the 2017 IEPR, looking probably of the hourly being more at the system level with plans to move that down to a more granular level as in the 2019 IEPR. But then using basically a bottom up from where is the loads and the load modifiers? At that busbar level we work a lot with the distribution utilities and the transmission owners as to what is the loading levels at that.

And that highlights the point that we talked about, the (indiscernible) of the alignment meeting as we're planning what assumptions are for the distribution system are rolling, to what is the transmission system. And is consistent with the IEPR forecast that's there as well as then what is being procured in making sure that those are consistent, is a critical component as we move forward. Next slide.

As we're working on terms of the transmission, and this from a planning, but it also has from an operational as we look at it in some degrees, is the planning the locational is a critical. Because as you get down the uncertainty gets will it develop? When does it develop? Does it develop to the magnitudes forecast right at the more granular you get down?

The other is of the uncertainty comes some of the output with the locational. The output will vary depending upon or the profiles will vary depending on the areas. So if we're looking at coastal versus inland versus in the south areas as well, the profiles are different. So having to work with those as well as some environmental impacts as we're looking at it as to cloud cover. What's the impacts of that as to assumptions to use for planning or monsoonal type heatwaves where you have high temperatures and you end up with high loads of that time period, but cloud cover. And having to make sure in terms of as we're doing the planning making sure that we have the resources or transmission facilities to be able to accommodate those types of conditions as well that may occur in time.

Other aspects that we have -- and I think Mark may have touched a bit on the distribution or the transmission as well as voltage regulation issues -- as we change or as the profile even on a daily basis typically you'd have a lot of changes beyond a seasonal. But as you're getting in terms of on a daily basis where the loading may go down in the middle of the day. It still has a high peak, making sure in terms of the voltage levels we're already seeing in terms of some of the areas high voltage occurring as we have those lower loads, particularly in the off-peak time periods.

The peak load shift is one as well in terms of from the planning to make sure just that we're accurately reflecting as that load is changing what does that do for other otherings, other resources at those times as well?

And then what it does do is with the changing and the profiles changing, increases the number of studies that we need to do particularly in off-peak time periods to assess what is critical system conditions? When you have the distributed generation that's there it's not the same as when you have energy efficiency where the load has actually disappeared and not there. You actually have the gross load that is connected to the system, you just have a different generation source that is supplying for it that has different characteristics of the conventional generation that was supplying.

So what kinds of impacts under where we would see on a low load on the transmission and distribution interface, but still a high load. Making sure things like frequency response, voltage regulation, transient stability under those conditions drives a significant amount more of studies that need to be done to identify what are those critical system conditions to ensure the system is (indiscernible) and operates in a reliable fashion throughout those different operating conditions.

And then the last really thing when we look at it is when we talked about it is as we modeled them. And it comes to the discussion of the smart inverters -- how do we do modeling of the distributed generation or the aggregation of a number of small generators into something that's reflecting how they're going to operate is the challenge as we move forward as well.

So that covers in terms of the presentation if there's any questions.

CHAIRMAN WEISENMILLER: Yeah, if you go back to the duck curve for a minute?

MR. BILLINTON: Yep.

CHAIRMAN WEISENMILLER: I just wanted to make sure people -- go back to that. The interesting thing as you can see is we got down to 8507, I guess it actually may have been 80 or somewhat lower after that, 83 or something. But when you look at the growth a couple of slides later on behind-the-meter knowing the additional renewables, it's easy to see that number go negative ten years from now, which certainly has a lot of fundamental implications.

But again if you just take that number and then you flip back to the slide on the growth of behind-the-meter and look at the delta -- yeah, that one. You know, you're actually doing the large-scale solar or other things, demand, energy efficiency, you name it that we're going to do, that could basically drop. Your minimum load could be negative, which certainly is sort of a new operational issue at that stage.

But having said all that, I guess the thing to ask you is obviously we talked about the distribution planning. You're looking more at the transmission and wholesale. Obviously we've been told the substation's where everything comes together. Again, what are the new issues we're going to come up with as the T affects the D and vice versa?

So I'm just trying to figure out as we make these big changes on the distribution side, what are some of the implications for the transmission system as we're operating it?.

MR. BILLINTON: Well I think, I think

CHAIRMAN WEISENMILLER: I think some visibility of what the distributed generation is, the forecasting, one from a planning but from the operational in particular, what those implications are.

MR. BILLINTON: The things around the voltage control? As you start changing flow direction, as you start changing how does that change things like voltage profiles or also the directional flow on lines, which has implications to protection systems as well, needing to look at it from those perspectives.

CHAIRMAN WEISENMILLER: Obviously, one of the things ERCOT worried about a lot recently has been inertia. Although I think they've talked themselves off that getting too panicky about it. But again, as we go through these changes what sort of studies do you need if any on inertia?

MR. BILLINTON: Well, actually we did some studies on inertia and two years ago, we were more focused in terms of as we looked at with the renewable on the transmission side. That's one of the keys, is we look at the uncertainties of the modeling of the distributed generation to make sure that we're getting realistic characteristics into the models. To be able to understand and find ways to address or mitigate concerns that may arise from the transient stability type or a frequency response, which is where you're getting the inertia.

Because like I said the load is still there, but it's being provided locally by generation that have different characteristics than what has conventionally been. Or also in terms of as was referenced in on the transmission connected where you may be able to have the larger ones with controls on them providing some of those services. When you have a lot of small ones spread out in an aggregation how do you get that kind of same characteristic response to provide that same kind of service?

And that's the purpose of why we've gone down the path to discretely model them and work to that to get so that we're making sure that we characterize these as we grow the level of generation.

CHAIRMAN WEISENMILLER: Yeah, I think that's why as we go into enhance -- as we go into more granularity that we have to enhance the granularity of our data. And that also means we have to reach out to some new entities like on vehicle to grid issues. You know, it's like who is running charging? How many of the sales are where?

So one of the things that is going to be critical for all three of us is that as we add more clean tech resources is to know where it is, how it's operating, and make sure that it's being incorporated in the forecast correctly. So that we're not missing any peak affects.

MR. BAKER: Yeah, kind of on that point is a question I guess perhaps to you, Mark. Setting aside the need for better forecasting of distributed energy aggregations, which was referenced in the earlier presentation, looking to the DRP process and the DER growth forecasts that are being developed there I'm aware that PG&E made some strides I think in their DRP filing. To try and develop some methodologies to produce more granular forecasts at the circuit level for DER growth using things like Beta on-air (phonetic) connection queues, economic demographic data where you might expect to see uptake of electric vehicles and PVs on your system, for example.

What's the current state of play of that? How do you actually get to a more certain forecast by using those more sophisticated methods? Or is it just piling uncertainty on top of uncertainty?

MR. ESGUERRA: That's a good question. Forecasts are forecasts and we're still working on how to -- part of it is trending back and looking at here's what we said and what did we learn? And how does it compare with reality? I think all of the efforts we're doing are trying to give us greater certainty, but at the end of the day we're still learning about what are all the different factors that are going to change. So I'd like to tell you that I can give you a firm number of how confident we are on these other items in terms of how the DERs are going to show up, but I will say that I believe everything we're doing is giving us more certainty.

But we also know that it may change with some of the concepts that are being kicked around in the proceeding. Is, "Well, can we bracket the possibilities of change? Do you need to adopt more scenarios that are book ends?" And so I can leave you with that, that we are coming up with our trajectory forecast but there's the discussions and cons about developing other trajectory scenarios. And really trying to put some probabilities behind it.

And when you start planning out your grid to understand what are the different levels of investments you need depending on what bracket of forecast. And being able to track this growth as it goes and materializes. And hopefully that the framework for improving investments is nimble enough that we can make certain changes or at least put in building blocks of investments that will be no regrets regardless of if growth changes or not.

CHAIRMAN WEISENMILLER: Yeah. That's good. I would say if you were here in January we had a workshop on econ demo and obviously we're pushing for more granularity. And if you look at the standard forecasters, it's more statewide you might something say for the Bay Area. But if you're really trying to find econ demo forecast really down to a very granular level statewide you (indiscernible) problem.

So if PG&E or anyone finds any better, please submit fast.

COMMISSIONER DOUGLAS: So just a quick follow-up question on that, what are some of the action steps that would be needed to get more granularity and be able to make more location-specific planning decisions?

MR. ESGUERRA: Well, I think it starts with data. I mean, I think there's just we talked about this, about access to more data about these others. But being able to trend back, I think one of the things we were thinking about here in terms of -- this is again for PG&E -- is being able to share some of that information, you know? And how does it feed into the IEPR process, particularly.

We know that there's a pretty firm schedule on -- and I can't remember which one -- the even year or odd year where there's one that's developed. Well, I think the utilities may have more information that have happened in between some of those off-cycle years. And being able to feed that in and to see how that could actually be reflected in maybe an update to the forecast. And I don't know all the details behind that, but that's the feedback I get from my forecasting team. Is that we'd love to be able to share more information that happens during these off-cycle IEPR years and see how it could be reflected in the forecast.

MR. CASEY: I just want to go back to the challenges Jeff raised in his last slide in terms of the planning complexity. Because I just want to underscore what a radically different planning environment it is compared to the old days -- that was two years ago.

In the old days you planned for your system peak and if you were confident you could meet that system peak, you had an adequate planning reserve margin, you were pretty confident you'd get through the entire year. And that paradigm is going away.

What's really more challenging now are these seasonal, what used to be off-peak shoulder seasons, where some of the operational challenges are greatest. And how we evolve our planning process to make sure we capture those most challenging seasonal conditions is a work in progress as Jeff's highlighted. And the behind-the-meter solar plays big into that, because you're seeing 6,000 today. It's going to double in ten years.

And what do you assume about that in terms of even in a seasonal assessment? Do you assume the worst-case scenario with a one-in-ten heatwave with monsoonal cloud cover? And if you can survive that you're confident that you can get through the season. Well, some people would say that's overly conservative, so what's the right answer there? And I don't think -- and I'll put it to Jeff or the other panelists if they think differently -- but I don't think we have a good answer to that. But it's something we're ultimately going to have to answer.

CHAIRMAN WEISENMILLER: Well, for the record I should point for those of you who are real data nerds, you're welcome to join Andrew and I as we're going through and expanding our data requirements. Which I would have to say has not been that warmly received by the utilities, but we're trying to deal with the granularity needs. But again, that's sort of a separate proceeding that's coming before the Commission. The first phase soon, and then second phase next year.

MR. FLYNN: Okay. I think personally for me that was an extremely informative panel discussion and great questions from the dais as well to help with that discussion. I'd like to thank Delphine and Mark and Jeff for joining us today and providing us with a lot of good information.

MS. RAITT: All right, thank you.

So we'll move on to the next panel, Publicly Owned Utility DER and Energy Storage Activities Update.

John Mathias from the Energy Commission is the Moderator. You can go ahead and get started.

MR. MATHIAS: Thanks, I'm John Mathias with the

Energy Commission's Distributed Generation Unit in the Energy Assessments Division.

For this next panel we have three presentations on what California's publicly owned utilities are doing in relation to distributed energy resources and energy storage. We have speakers from the Northern California Power Agency, Imperial Irrigation Districts and Los Angeles Department of Power and Water. So the first presentation will be Jonathan Changus from the NCPA. Jonathan is the Member Services Manager and also responsible for Regulatory Affairs at NCPA. He's going to provide an update on what the POUs are doing on energy storage as it relates to AB 2514.

And Energy Commission staff we've been coordinating with NCPA and other POUs regarding this, because a lot of the requirements of AB 2514 require report submittal to the Energy Commission. And we plan to continue coordination with them as we go forward, so Jonathan?

MR. CHANGUS: Great. Thank you and it's a pleasure to be here speaking on behalf of NCPA first and foremost, but I do frequently play in the same policy sandbox with a lot of the other POUs. So there's some information I can share as well regarding AB 2514 on a joint effort in particular with SCPPA that has just completed this previous year.

I do want to note that my comments will be probably be probably more biased towards the smaller Northern California power agency members, as far as what their concerns and their considerations are. And I will do my best to speak to some of the other non-NCPA member issues and what I've learned over the years as far as their concerns.

And then finally, we will be submitting updated target information to the CEC by October 1st as required by statute. And with that I think we'll just get started.

Not to do too much of an overview, because I think most folks in the room are familiar with the requirements of AB 2514 with regards to publicly owned utilities. Their local governing boards were directed to evaluate energy storage technologies and to determine what if any appropriate procurement targets might be that are cost effective and feasible.

The initial targets were adopted by October 1, 2014, which is what triggered this three-year reevaluation of 2017, and then we will also do another in October of 2020.

And I'd be remiss if I didn't note that that's what we're primarily addressing in October is going to be the 2514 requirements. But with the passage of SB 350 and integrated resourcing planning, energy storage is becoming more of a feature in those larger resource planning activities coming down the line as well. And so the October reports really speak to I believe what they determined to be prudent for 2018 through 2021. But I anticipate that as we go through the IRP process too, this is a really rapidly evolving area and there could be some changes down the line. Next slide.

So last fall, NCPA and SCPPA contracted for a joint evaluation of energy storage technologies. And we were really looking for storage interests in common to POUs across the board. And so that was primarily focused on technologies and services that they could provide at the distribution grid level.

For smaller utilities that are not a balancing authority (phonetic) it's very different math in many cases as far as what the role and value potentially could be to the utility regarding storage. And so we know that a lot has changed since 2014, but for the IOUs and in the energy storage market in general. And so we were seeking kind of a third-party review of what the technologies were now capable of, what some of the cost trends were, what some of the applications might be. And part of that was, in particular a review of the work that'd been done by the CPUC for the IOUs. And what was motivating some of the investor owned utility procurements and solicitations, especially in Southern California.

In addition to that joint report, which we received earlier this year and has now been distributed to members, SCPPA has also contracted with Navigant for some additional kind of member-specific modeling. What we were seeking and what we received from DNV GL wasn't a utility-by-utility target setting or information like we do for energy efficiency. It was more case studies, use studies, of storage technologies and different applications. And what some of the cost numbers look like with a recognition that for any individual utility, the conditions as far as their grid and their needs, would dictate and inform what some of the applications were.

So we had some reference cases included. We had some review of the technical capabilities and some cost data. And it was designed and meant to inform additional work by the utilities, not to essentially set the potential goals or studies like we do for energy efficiency. So SCPPA has a separate contract going with Navigant to do some more specific modeling for individual members.

And in addition, independent of the joint NCPA and SCPPA report, is also Lazard Levelized Cost of Storage Analysis 2.0, which came out in December 2016. And does, I think, a pretty excellent job of kind of going through a number of the similar questions we were asking DNV GL but for a broader range of technologies. And that is also something that members will be looking to as they try and evaluate their future resource needs. Next slide.

So in particular, in January we provided an update to the CEC about kind of the interest areas when it comes to publicly owned utilities with regards to energy storage. And I think there's potentially a misconception, which is on our part is the public power to kind of correct the records as far as engagement and interest when it comes to energy storage. Because as everyone knows, most POUs did not adopt energy storage targets in 2014. But that does not mean that there was not energy storage activity.

And so these interest areas are kind of a reiteration of kind of where we've been and what we're looking to going forward. Even if it's not necessarily with formally adopted procurement targets there's still going to be some activity.

So the first area of interest and activity that's been around for a number of years is RD&D pilot programs. LADWP and SMUD being the largest POUs have the more robust programs. I believe since 2008, SMUD has invested something around the lines of $30 million of internal, external funds into storage research. SCPPA sent me notes to make sure I got this on the record, has a current thermal energy pilot program in which three of their utilities: Azusa, Colton and another one -- Riverside -- are participating in to demonstrate thermal energy storage. Alameda, an NCPA member, has a very small kind of fly-wheel research program demonstration project going on as well. And so there's a hodgepodge of these types of activities, which I'm happy to explain in greater detail if that's of interest.

And then we also participate in a number of research institutions and organizations that do research. Many small POUs are not going to have a robust RD&D program of their own. But we participate in things like the APPA DEED Program, the SEPA has done a variety of webinars and research papers as well as EPRI and E-Source. And so we rely a great deal on some of those sources of information to help keep us abreast of what's going on and new considerations that we might want to consider.

The second major area is renewable and storage procurement. And in particular, being informed by now the integrated resource planning process. And so NCPA and SCPPA have already kind of initiated joint RPS-eligible project with storage as an option. I believe at this time it was not included, but it's something like EV chargers in your garage. We wanted to make sure that the sight and location is capable of adding storage if that is desirable at some other point.

And that's a feature as well, of upcoming communities, solar programs, and projects that POUs are considering. Roseville, (phonetic) I know has a thought at this point that energy storage might be appropriate to co-locate at their proposed community solar program. But that's still coming down the pipe a little bit.

And the RPS plus storage procurement too, has also learned a great deal from the IOU solicitations. And we've had some folks come in and speak and so it's very much, "What are we doing ourselves, really?" We tend to be second adopters at the NCPA level at least, as far as some of these major changes. And learning from others is critical to our steps forward.

The next step, which does not necessarily speak as much to NCPA members as it does to some of the activities going on in the state, is with SONGS and Aliso Canyon and once-through cooling issues. That we're all aware of the impacts of those kind of very sudden changes in grid infrastructure changed the dynamics, at least for some of the Southern California utilities. And I know those are issues that are under consideration and will be more thoroughly addressed, I believe in the October filings as far as whether or not to adopt procurement targets.

And then finally one of the major issues in areas of factors that goes into decisions with regards to procurement, is the market conditions. In particular within the CAISO and we've had other presentations about trying to overcome some of the barriers to allow energy storage and other DERs to participate more fully. And we're getting there, progress is definitely being made and we're trying to understand what those opportunities might actually look like.

But I will note that there is some question about stranded assets and (indiscernible) is created with regionalization as most folks view energy storage as a way to help address the over-generation and optimization of our renewable resources. Regionalization, if it were to move forward, also addresses a lot of those same challenges. And as we're seeing stranded asset issues already with utility investments, there is I would say some caution about moving forward in trying to understand just exactly what the opportunity is going to be for a more wholesale or large POU investments in more central station energy storage.

I think I can say with some confidence that a number or the smaller, mid-size POUs are really focusing on energy storage as a distribution and kind of a behind-the-meter resource as that's where the most appetite may be, in their service territories.

And so that's what I have for energy storage. I also handle transportation electrification, energy efficiency, and distributed solar. So if you have other DER questions I'm happy to answer.

CHAIRMAN WEISENMILLER: Just on your last point, which I'd probably characterize as a Lodi point, I would point you to Rainer Baake before he became the Energy head in Germany. He was with Agora, one of their leading think tanks, and he wrote a marvelous paper a number of years ago. "Twelve Ways and Twelve Truths."

And on storage he basically ranked things as, you know, technologies have changed, but anyway the cheapest way to store is in the Grid. Basically for Germany, that turned into regional with the interconnect. Obviously, with Poland and France etcetera and also connecting to Denmark. So in fact, the first time I met him he'd just come back from -- (indiscernible) trying to say, "Okay, can we store our surplus solar in your hydro system?"

And then the second rank from his perspective was thermal. You know, again a no-brainer, it was very cost effective. He was not as enthusiastic on batteries, so other things have come along in sort of the top of his list in terms of cost or issues was power to gas.

But anyway so as you look at stuff, the sort of regional storing stuff in the Grid, dealing with diversity and thermal should be no-brainers on some level.

Yeah, now as I said I know you have a particular asset you're struggling with, but at some point you've got to deal with the facts as they are. You know, you can't be K. Kanut, trying to prop up something which is stranded.

MR. CHANGUS: Absolutely. And I think just in response to thermal too, I know Redding has completed a five-year program with thermal energy storage. And the assumptions and the conditions there as well had changed dramatically, of course from when they started. And for some of their applications where they were looking at working with schools and trying to shift that load from 12:00 to 5:00, that load now has a very different economic piece.

And so I absolutely agree that thermal is proven. It is what the SCPPA project is looking at right now and there's still a lot of opportunity.

CHAIRMAN WEISENMILLER: Okay. Anyone else?

(No audible response.)

MR. MATHIAS: Thanks, Jonathan.

The next panelist is Chris Beltran. Chris is a General Superintendent in the Energy Department as Imperial Irrigation District. And he's here to present on Imperial Irrigation District's 20 Megawatt Battery Energy Storage System.

MR. BELTRAN: I'd like to say thank you to the Commission for letting me come here. When I got the invite I was like, "Wow, I get to go to Sacramento. I've never been there." This presentation, I've learned a lot from the other ones, but this one is pretty how we started to where we are now with our batteries. So at least we'll start, next please?

Imperial Irrigation District, or IID, is a publicly owned utility that provides water and power to more than 140,000 customers in Imperial County and portions of South Riverside and San Diego counties. And IID was formed as an irrigation district in 1911, so we're servicing nearly 500,000 acres of farmland before expanding into the power industry in 1936. IID is now the 6th largest electric utility in California and one of the five balancing authorities in the state. Next, please?

For over a century, the expanse of farmland and crops have benefited from 309 average days of sunshine. IID's energy portfolio has more recently capitalized on this available solar energy. And now provides 25 percent of its power from renewables and expects this number to rise at 35 percent within the next few years. However, this increase in renewable resources have resulted in fluctuations not previously experienced by IID. Next please?

In the case of the solar energy production, the famous duck curve has become more apparent lately as solar energy sources drive download demand during sunlight hours. Additionally, scattered clouds have ability to change load demand quicker than conventional generators are able to respond. IIDs concerns with this, with the renewables and other system reliability concerns were addressed with the first battery energy storage system or BESS. Next, please?

IID first researched existing best projects already in operation, and ultimately teamed up with Power Engineers to design their system. Some of the research and best projects in operation were primarily used for spinning reserve capacity. However, IID desired a best system that would primarily help smooth out the energy fluctuations from solar energy sources. Next, please?

Next a load study was conducted, and a model was created to determine how the BESS may affect the nearby transmission systems. This study with modeling concluded that a 30 megawatt system capable of 20 megawatt hours of storage would be the most appropriate sized system located in El Centro Generation Station in El Centro, California 120 miles east of San Diego. Next, please?

The next step involved determining various design characteristics that best suited IID's needs. Excuse me, 5,032 Samsung American lithium ion batteries were selected for the IIDs BESS as they were completely sealed. And do not require electrolyte maintenance that is common with nickel cadmium batteries. Each weighs about 100 pounds, about the size of a computer, desktop computer and they say the life expected of 18-to-20 years. But I'm sure it's going to degrade over the time, but we'll find that out pretty soon.

IID elected to have the BESS built onsite as opposed to having modular units built offsite and delivered, therefore avoiding the need of having individual HVAC units on each module. Coachella Energy Storage Partners was contracted to completed engineering construction, while GE was selected to deliver the components necessary to build the best.

ZGLOBAL, Tri-Technic and Chula Vista Electric Company also played important roles through the design, construction, and testing phase. I know that almost sounded like a little sales pitch, but I'm sorry. Next, please?

Construction of the BESS commended November 2015 and avoided the 110 degree heat we usually have in the Valley. Last week, last Tuesday, it was 122 and it was -- but that was a good test for the batteries in the HVAC system. The 110 heat, that's normally during the summer months in Pearl Valley, these cooler conditions also aided to the proper concrete curing of 300 cement trucks loads required for the project.

The building is constructed on a concrete pad, occupies about 8,000 square feet that houses the batteries and control room. Cooling the building requires 220 tons of HVAC to maintain the building at 78 degrees. Next, please.

The BESS is designed with reliability in mind as evident of the 30 individual banks that operate in parallel each consisting of a set of batteries, inverter, and transformer. This redundancy allows for continuous BESS operation in case a bank requires maintenance. Each of these banks is then connected to a main transformer and finally routed through a '92 kV substation connected to the Grid.

So if there was a problem with one strings, you could just isolate one of the strings. And you would not lose your capacity of the BESS, instead of shutting down the whole thing. Next, please.

The BESS became fully operational in October of 2016 and provides several operational modes, which include spinning reserve, solar following, e-con, area control air, which is called "ACE," frequency response black-start and manual override.

Initially the BESS was operated in econ mode based on economic factors. However, it was difficult to determine the set points and it didn't result in frequent charge and discharge cycles. Next, please.

IID has found most beneficial to operate the ACE control mode to smooth out the fluctuations from the solar energy sources. Operation in this mode has also supported NERC Balancing Authority ACE limit or BAL events and contributed to a reduction in BAL exceedance. A key advantage to the BESS over conventional generating units is that it's able to respond a lot faster in as little as a couple of cycles. Next, please.

Some of the other advantages IID has recognized from the BESS include benefit of shutting down conventional combined cycle units by allowing the BESS to serve as spin reserves. It's also beneficial that BESS operates at a plus or minus 30 megawatt, providing a 16 megawatt dynamic range. Gas turbines have also been avoided through the use of the BESS -- starts, excuse me, next please.

In summary, IID finds the BESS is best suited for scenarios where fast response is needed over a short duration. At a maximum discharge rate of 30 megawatts and fully charged state of 20 megawatt hours, the BESS can operate for 40 minutes.

May 10th, 2017 IID successfully black-started Unit 32 at the El Centro Generating Station using the batteries, providing additional system reliability. I was told it was the first time it's ever been done. I don't know. You probably know more. Next, please?

Finally, the BESS is configured to allow for five additional Hunt 1.25 MVA battery banks. The success in savings IID has recognized with the BESS has already generated interest in expanding it to five additional slots.

I'd like to say thank you for letting me share my story.

CHAIRMAN WEISENMILLER: No, thanks. I mean, we appreciate you coming. Certainly it's an interesting story here. I guess I was just trying to understand, first of all I mean in terms of the cost of this, was it on time, on budget or you know, I mean I understand this is more of a FERC settlement, but --

MR. BELTRAN: Yes, sir. It was on time. I didn't know the budget, but it cost $38 million. I know the FERC, after that problem we had it was like we had to spend $9 million and our people decided, "Let's do this." It was above my pay grade.

CHAIRMAN WEISENMILLER: Yeah, no (indiscernible). Yeah, but I certainly encourage the POUs to visit and kick the tires there. Not necessarily in the summer, but anyway. (Laughter.)

MR. BELTRAN: I've given tours at least twice a week. You can't imagine the people that want to come down and see it, still. It's unreal and they're coming down when it's 110 degrees.

CHAIRMAN WEISENMILLER: That's good. That's good. What in terms of we hear a lot from the ISO about the duck curve, we hear a lot about their ramp, as you had more solar what's going on with you in terms of minimum gen ramp? I mean, is this the solution or do you have more?

MR. BELTRAN: Well, they're planning on maybe another battery storage. I know that our older units, our fleet, they can't back down as fast. And these batteries, they're like that. Especially with all the solar coming in, in the morning and our combined cycle units trying to back down, well they're not running as many of them as much. And so -- or their peak units or something, excuse me.

CHAIRMAN WEISENMILLER: Yeah.

MR. BELTRAN: And they're using the battery for grid support, pretty much. And they'll put a set point on the ACE like 15 megawatts plus and of 15 megawatts minus. So it just comes in, in cycles all day long. But that's SOC. That's dispatch's little toy. Now me, I'm just over at the plant. We just make sure it doesn't catch on fire and give tours.

CHAIRMAN WEISENMILLER: There's (indiscernible)

MR. BELTRAN: Right, yeah.

CHAIRMAN WEISENMILLER: Yeah, there was the A123 battery that burned down the one farm in Hawaii. But anyway, so stay on your toes.

But yeah, I was going to say on the variability, I mean when I look at Keith's stuff he's looking at solar over a much broader geographical area than you are. So there's got to be a fair amount of volatility there, the same on distributed resource mixes. Much more concentrated and fewer wind farms or whatever.

MR. BELTRAN: We do have some wind farms, but it's challenging and our engineers and our system ops, well it's affecting everybody. And they're just trying to figure out how they best can use the best to our advantage for this problem.

CHAIRMAN WEISENMILLER: Yeah, one of the things I know certainly in talking to some of the German scientists and here, you come back to as we change, what are the basic metrics we should be following on balancing authorities? You know, and the sort of classic reliability, what's your reserves or stuff like that, just things are changing fast. So just how to operate.

MR. BELTRAN: It's an interesting time.

CHAIRMAN WEISENMILLER: Yeah, certainly. That's good, thanks.

Anyone?

(No audible response.)

Good, next please.

MR. MATHIAS: Thanks, Chris.

The next two panelists are from the Los Angeles Department of Power and Water. We have James Barner who is the Engineering Supervisor of Integrated Resource Planning and Jason Rondou, the Engineering Supervisor of DER Programs. And their presentation on LADWP's Distributed Energy Resource Planning and Programs.

MR. BARNER: Hi, I'm James Barner. I'm here with Jason Rondou who's in charge of our DER programs. I'd just like to give you an overview, next slide please, our IRP overview to let you know how we incorporate DER into our planning process. And then we'll talk about our system studies and research that we've done recently. And then Jason will talk more about the distributed energy resource programs that are parts of our DER Program. Next slide.

So LADWP, this last past IRP cycle, we do it every year annually, we've been including DER programs in our planning process, in our modeling for our IRP since 2010. In the future, we're going to be going to very high levels of renewables, 65 percent by 2036 and 55 percent by 2030. This is all while achieving 15 percent energy efficiency by 2020. And we're doing a new potential study to look beyond that point of implementing more energy efficiency on our system. We recognize that these distributed resources system add a lot of diversity to our renewable portfolio. It takes the pressure off of our transmission lines and the different programs that we've have: energy efficiency, rooftop PV, local solar, demand response, electrification of EVs. Next slide?

So this latest IRP adopted a goal of 1,500 megawatts of distributed solar by 2036. When we first started the IRP process we were looking at somewhere around 300 megawatts and we didn't believe we could go higher than that on our distribution system. And since then we've done several studies that have shown otherwise. And we believe we can go to a higher level of 1,500 megawatts of distributed solar on our system.

That also includes energy storage, a portion of which would be on our distribution system. We now have adopted 404 megawatts as our aspirational goal for energy storage by 2030. About 44 megawatts of that will be on the distribution system and I'm not sure how much will be on the customer side versus the distribution station side. But that's to be determined.

Right now, as you can see, local solar is a big part of our overall solar program and it does take a big portion of our renewable program costs to implement local solar. It's more expensive than other types of renewables on our system, but does have benefits on our grid. The next slide?

So we conducted a Maximum Distribution Renewable Energy Penetration Study. This is similar to the Integration Capacity Analysis that the IOUs did. And we looked at evaluating our circuits. We have 1,600 4.8 kV circuits and 600 34.5 kV circuits and we kind of have a dual voltage distribution grid. The 34.5 kV system is heavily networked and we model that with the power flow when we have a good data from that system. The 4.8 kV circuits, they're radial circuits. They're usually shorter in length.

And what we found from the study was that basically we can manage this interconnection process. If we manage it properly and look at not exceeding certain limits on each one of these feeders, that we could actually put a lot more distributed resources on our system than we originally thought. Some circuits can take up to 60 percent penetration, some can only take 15 percent. So managing that and understanding and having the data available we found was very important. And we understood from the study, that we really need to do more work on our 4.8 kV system. And modeling that and modeling all the components of each one of those feeder networks. We did model 18 of those in detail in this study.

And then I'd like to turn it over to Jason. He's going to talk about a DERIS Study that we recently had, recognizing that we needed to integrate our programs together. A lot of our effort in IRP was to accelerate these programs and increase the budgeting and the staffing for these programs. Get them off the ground. And so to manage those programs we did a DERIS study recently and Jason will take over.

MR. RONDOU: All right, thank you.

My name is Jason Rondou. I manage our newly created DER Program Office and so to follow on to the Maximum Renewal Penetration Study, last year we launched a DER Integration Study. And what that really did is it took a look at what our future is going to look like. The graph on the left is really similar to what a lot of utilities will probably experience in the 2030 timeframe. Particularly in the spring months where it's nice and cool and we've got significant solar generation. And so you've got the large ramp and potential over-generation scenario.

So what it did is it looked at our programs, our processes, as well as our organizational structure. And made a series of recommendations for the Department to implement different changes to existing and future programs. Next slide, please?

And so as a result of the DER integration study we actually started to begin to implement some of these preliminary findings such as creating some tools for our distribution planners to update their processes by which they integrate solar and other DERs.

We've also started to begin to implement some of the organizational changes. As I mentioned we recently created our DER Program Office in our Planning Division. And so that will likely be the first of many organizational changes that we make to better plan and better manage and better incorporate distributed resources. Next slide, please.

So as James mentioned a moment ago, a significant portion of our renewable portfolio is solar. And a significant portion of that is local solar and so that will likely be comprised of the four existing programs that we have today. Most of which are customer-focused. Next slide, please.

So we still have a Solar Incentive Program, which is our version of the California Solar Initiative. We launched that in 2007, but we actually predated that launch with incentives back starting as early as 1999. And so at the end of 2015, rather than closing the program we continued it to fully expand the remaining incentives. And so we've got probably about $10 million of incentives to date. A number of things that happened recently, back in 2015 we made the commitment to incorporate behind-the-meter solar to levels that would be consistent with the 5 percent non-coincident peak that the investor owned utilities have adopted. And we don't really have a cap, but we sorted of committed to not changing the terms prior to reaching that level.

So today we've got over $300 million paid. Another notable fact here is that we had to, back in 2007, offered a pretty significantly higher incentives than a lot of the rest of the state. And that was in large part due to electric rates being relatively cheaper and making the solar payback for customers a little bit longer and a little bit further out than the rest of the state. And so that actually did help ramp up pretty significantly, and we actually ended up seeing a pretty significant spike a number of years ago that required us to make substantial changes organizationally in order to actually get service levels to an acceptable level.

So we were at almost two months to get customers integrated back in our worst backlogged times. And now we're down to days and it's actually a little bit more difficult for us to do that relative to a lot of the investor owned utilities and some POUs that have a fully deployed AMI deployment. And so we actually still have to go install net capable meters, so that's it make a little bit more rigorous. But we've still been able to manage to do that actually in a number of days, so we're very proud of that. Next slide, please.

So complementing our Solar Incentive Program and Net Metering Program is our Feed-in Tariff Program, which is generally more geared towards large and mid-sized commercial. And the major difference between this and net metering is that it's grid connected, so we purchase under power purchase agreements 100 percent of the energy for 20 years for a set rate.

There's a state mandate to do that at a 75 megawatt program level and we doubled that a number of years ago. And as of today we're probably a little bit less than 50 percent adoption rate. And tomorrow we are making available the remaining about 65 megawatts of that program, so we're pretty optimistic to see a pretty high adoption of that over the coming six months or so. Next slide, please.

So this is a recently completed rooftop distributed solar project in our service territory down by the Port of Los Angeles. It's 15 megawatts AC. It's actually comprised of a number of individual 3 megawatt projects that are individually metered, but 100 percent of that energy is being purchased by LADWP. We're able to contribute this towards our renewable portfolio standard. Next slide, please.

At the residential level we've also recently launched a rooftop program where we would actually install residential solar and lease the customer's roof and provide an incentive of $360 per year. And a little bit later this year we intend to launch a shared solar program where customers could subscribe to shares of solar that would be located either locally in our distribution grid or potentially offsite as well. Next slide.

And we touched on this a little bit earlier with a previous presentation, but we do have 175 megawatt target, which a little bit further out -- 2035 or 2030 we've increased to 400 megawatts of energy storage. To date, we've got obviously our Castaic-pumped storage, but we're going to be going forward with a 20 megawatt battery storage facility co-located at our Beacon Solar 250 megawatt solar project out in the Mojave Desert. So we're very, very excited about that project as well.

And what we've also been doing lately is assessing the feasibility of doing solar storage resiliency projects on city and LADWP facilities, particularly critical facilities. And so on the next slide you'll see the first of those, which will go live later this month.

This fire station will have about 50 kilowatts of solar in a storage system as well. This happens to -- not happens, but it's located in close proximity to the Aliso Canyon Storage Facility. So the significance of this is really making it sort of a statement project that signals our commitment to adopting this type of technology and actually expanding this to, as I mentioned other critical city facilities. And also gaining sort of knowledge of the engineering and construction and interconnection of these types of systems. So while it's a small system it has a pretty large significance for us. Next slide.

Historically on the DR front we haven't had a significant and robust DR program, in part because we hadn't quite needed that. But with obviously very, very high levels of renewable integration and the continued option of DERs, we do project to see a big need for demand response in the future.

And so as it stands today we've got a plan for 500 megawatts by 2036. But as a result of the DER Integration Study that will be completed later this year, we expect that this target may get dialed up. And sort of those findings will get fed into our Integrated Resource Plan and that'll get updated as part of that.

So a couple of recent updates on this is we are developing and hoping to launch and have in place by next summer, a residential program. We have a C&I program currently in operation although it's very young. And last summer we launched what we called the SummerShift program, where we encouraged through rate incentives our very, very large customers to shift their load due to a variety of different ways that would be most suited for them. And so that was a successful program that we piloted last summer and will be continuing this summer as well. Next slide.

We also have a fairly ambitious Electric Vehicle Program. We hope to have 145,000 electric vehicle equivalent in Los Angeles over the next five years. We have residential incentive, $500 per charger, and $4,000 for commercial chargers. We also are pretty aggressively doing direct install on LADWP and City of Los Angeles facilities as well where we actually will deploy those charges. And very often will deploy the Level 3 chargers as well.

There is a growing desire to see our EV ambitions grow significantly. So that will be something that we will be studying very closely and very soon. Next slide, please?

This is just a few pictures of some EV pole chargers. I think we were the first utility to have one of those. On the right side, you can see a very sleek one that's attached to a utility pole, which is particularly important in Los Angeles given our demographics and how sort of spread out we are and how many opportunities we have for something like this. Next slide.

And finally, as James Barner mentioned earlier, we've got a 15 percent energy efficiency goal, which is a very, very significant goal. So as of last fiscal we were ahead of target to meet those goals. And it requires a pretty substantial investment to deploy those, so we've got a very robust portfolio of the energy efficiency programs from direct install to incentives for customers as well.

So I think with that I'd be happy to answer any questions that you may have.

CHAIRMAN WEISENMILLER: Again, I thank both of your for being here. I would note that actually on Aliso Canyon, the one good news was getting the opportunity to work with Marcie Edwards pretty closely on stuff. And actually to really deepen the relationship between the Energy Commission and CAISO and the PUC with LADWP, confronting the issues down there.

But with that in mind, there's sort of one thing, which we've really had to emphasize as we were going through the reliability studies, is really enhanced energy efficiency and demand response. You know, particularly in the summer when we got lucky recently. If you look at the weather charts, although it 125 in Blythe, Santa Monica, San Jose and San Diego never quite all went above 95, which would certainly make all of us pretty nervous. And so actually Sacramento's pretty miserable, but at least the major load centers were not hitting really high temperatures. So we weren't really -- things were a lot better than they could have been.

But again, I think as President Picker said last year at our Aliso meeting FLEX is not a good policy. So short-term we have to really step up what we can do on the demand response. What we can do on energy efficiency. Obviously Edison's already stepped forward a lot on storage, so certainly if in any of the storage you're thinking of if you can do it sooner rather than later that would be good.

And then certainly the PUCs, we know that assigned Commissioner ordered recently a new OIR on Aliso and made clear that the PUC is taking it pretty seriously in a legislative direction to figure out if there's a way to basically move away from it as a facility. And that would certainly have implications for you as a generator and so again it's important to factor that into your planning also.

MR. RONDOU: Yes, absolutely. And we, last summer, accelerated a number of our projects and programs. Our C&I DR program, we doubled based on previous targets for that year. We intend to continue to aggressively push forward with that and that will be a driver for our planning going forward as well.

CHAIRMAN WEISENMILLER: I guess the one question I'm trying to understand a little bit, is you heard a lot from the prior panel about the various working that they're doing with More Than Smart. I don't know if LADWP or even NCPA is (indiscernible) them. You had the long list of who you were following on some of the storage stuff, but in terms of participation in that process.

MR. CHANGUS: Yeah, NCPA is a member of More Than Smart and I would say probably in the last four months was more actively engaged. But the Annual Energy Efficiency Report and the Solar Report take up a lot of my time as well. But yes it's something that we very much think that the partnership, and the work product and the great deal of effort that's gone in there has really helped advance our knowledge as well as well as far as distributed energy resources in the future had. So it's something that we're very mindful of them paying close attention to.

CHAIRMAN WEISENMILLER: Yeah, again and a lot of this originally came out from basically Cal Tech, so it's certainly an entity, which is you guys rely upon on some level. So certainly I encourage you to at least look at it and figure out whether it adds value.

Anyone else?

MS. BROOK: May I?

CHAIRMAN WEISENMILLER: Sure, yeah.

MS. BROOK: So I was interested in your Community Solar Shares Program. One of the issues that we have for our Building Standards where we want to require some amount of onsite generation, we wanted to have a community solar option. But our concern is that a customer can sign up with you or SMUD or another utility for a community share program, but there's no obligation for that relationship to continue.

Do you offer or would you consider offering like a long-term contract where there would be an obligation for them to stay buying into that program for say 10 to 15 years?

MR. RONDOU: So the framework of what we had anticipated launching, and the details are not firm, but we intended to do something flexible that was something that a customer could withdraw from if they chose to do. So as is currently envisioned, it would not be a long-term commitment. But that is absolutely something that we can look into, perhaps there would be a version of a program. Maybe there'd be a portfolio of something or a subset or an option to do that, but that's something that we could look into. But it's currently not envisioned to be.

MR. CHANGUS: And I would note Plymouth Sierra (phonetic) is actually the first of the NCPA family to be moving forward with the community solar program. It should go live here later this year and their model envisions a 5, 10, or 20-year subscription. And it's one of the major topics that we're discussing is not wanting to discourage participation by requiring a long-term commitment.

But just if you don't have that long-term commitment then it shifts additional risks to the utility. So the pros and cons of both, and that's very much one of the key concerns that folks are working through.

MR. MATHIAS: Thanks to panelists for taking --

CHAIRMAN WEISENMILLER: Thanks, a lot. Let's go on to the last panel.

MS. RAITT: Great. So our next panel, the last panel of the day, is on Stakeholder Perspectives on the Implementation of DER Action Plan. Matthew Tisdale is the Moderator.

MR. TISDALE: Should we begin?

MS. RAITT: Yeah.

MR. TISDALE: Great. Good afternoon. My name is Matthew Tisdale. I'm the Executive Director with More Than Smart. It's great to be here and I appreciate you inviting me to moderate this panel. I also appreciate how full the dais has been today and how full the whole room has been.

Indeed, the whole discussion has been quite one might say, teeming with interesting issues and progress. And for those of us who have been working at this for a while, it's a very gratifying to see that momentum and that interest. So thank you for your attention and ongoing support.

More Then Smart is a nonprofit organization. We're based in Oakland, California. Our mission is to support the integration of distributed energy resources into the Grid. And we believe at the core of that mission that doing so will make the grids cleaner, more reliable, and more affordable.

And one of the ways we do that to support that mission is by supporting working groups. One of the working group products was referenced and presented earlier by Mark Esguerra in the T-D Coordination Operations. We're very excited about that and thank you, Mark, for being here to present it.

Other members of this panel are active participants in our working group as are other members of the audience today. So we acknowledge them and thank them for their participation, because it's really the life blood of what More Than Smart does.

The objective of our panel here today is to sort of maybe accomplish two objectives. One, season what we've heard here so far this afternoon with some outsider perspective, perhaps some disrupter perspective. And two, to ensure the imperative of serving customers remains at the front and center of this discussion. And we do have some folks here who have customer satisfaction for breakfast. And so we want to make sure that their perspective is well represented.

The panelists who are joining me, they need no introduction. So I'll just give you their names and then let them dive into their perspective: Mark Esguerra, from the Pacific Gas and Electric Company, to my right; Damon Franz from Tesla; Jim Baak from Vote Solar and Carmen Garralaga from SMA Smart Inverters.

So thank you all for agreeing to participate here today. And with that I will turn it over to Mark.

MR. ESGUERRA: All right, thank you. Good afternoon. And I will just clarify that I am just representing PG&E. I know the earlier agenda had joined IOUs, but my thoughts and my responses are more from PG&E's perspectives only.

So specifically within PG&E, the team I lead is focused on Integrated Grid Planning. And essentially a lot of the work that we're doing in Integrated Grid Planning deals with distributed energy resources, the Distribution Resources Plan, as well as the Distribution Energy Resource Provider Tariff. So from the DER Action Plan, there's three distinct tracks as you heard Simon go over this morning. One was focused on rates, the second was on Distribution Grid Infrastructure Planning, and the third was on wholesale markets.

A lot of the focus in the work that my team does, and the perspectives I have, are really more around the distribution grid infrastructure planning as well as the interconnection process for wholesale participation for DERs.

So some of the perspective we have on the implementation efforts, we talked a lot about the efforts of data and I'll use the framework of the overall planning process. So the planning process essentially starts and is grounded for the load forecast and DER forecast. And PG&E's perspective is that we very much want to -- we can continue to align and adopt the forecasts that are set forward by the CEC, which are then adopted and utilized in the transmission planning studies.

And so PG&E believes in utilizing those same forecasts. To the extent that there are, let's say differences or there's huge changes, we'd want to take a closer look. Is there a reason to adapt, which goes into some of my earlier comments about being able to provide more updates during off-cycle IEPR years. Is there an opportunity to provide new information if the utilities have something that's showing we're seeing different levels of growth.

Some other interactions we have out there is that we are leveraging a lot of work that's coming out of EPIC. So we've done some work in terms of being able to pull the smart meter data at the end user and being able to interface that into our planning models. And what we're seeing there is giving us a more better depiction of our overall planning.

And in the other work that you heard referenced is once you've done some of the forecasting improvements, we've also been working on trying to understand what impacts DERs are going have on the Grid. And since we've done a lot of work on developing a methodology on hosting capacity, More Than Smart has been facilitating a lot of those working groups. It's been moving long, relatively well. We believe we're going to come to a good place where there's a methodology that the utilities can work behind.

And then the last item here is we're really focused on the Locational Net Benefits Analysis. So More Than Smart is facilitating a lot of work in that area. We believe we're moving the needle in that space to better understand what the net benefits are.

One point that PG&E would add, as potentially something to consider in the net benefits, is really the articulation or somehow how do you factor the actual cost or costs of DERs in order to really understand the true net benefit for ratepayers? So being able to make sure that we don't separate those two items when we're developing any of their tools and methodologies. So I'll pause there.

MR. TISDALE: Thank you, Mark.

Damon?

MR. FRANZ: Sure. Hi, my name is Damon Franz. I'm a Policy Manager at Tesla. I'd like to thank the Commissioners and staff for holding this hearing today. I think this topic is working towards a generational shift in how we think about electricity from the very monopolistic centrally-planned electricity grid to one that relies much more on distributed resources owned by customers, supplied in a competitive market.

And I think if it's done correctly, it will produce a grid that is not only cleaner and addresses a lot of climate and pollution issues, but also mitigates a lot of local impacts for large infrastructure projects on water and wildlife. And hopefully creates a more efficient and low-cost grid, so I'd like to thank you for holding this hearing.

I'd like to address one comment that Chair Weisenmiller made earlier, that the Grid is the most cost-effective storage resource followed by thermal and then batteries. And I think if you think of storage or you think of a battery as just something that absorbs energy at one time and releases it later, that might be true. But the way we look at a battery is that it provides a whole range of services and values to the customer who owns it, also to the Grid and to other customers. And it you stack all those values, you actually get a very cost-effective resource that can actually do a lot of things.

For example, a lot of the batteries that we deploy and have deployed to date, customers are buying just for backup power. So in areas where there's not great reliability they value that battery just for backup power.

We also deploy a lot for demand charge management, for commercial customers. And so those are basically just two value streams out of probably 13 or 15 that have been identified by groups like Rocky Mountain Institute. And I think the task of the grid integration folks that are working on it is to unlock a lot of those other value streams meant to create a resource that can do things like manage the duck curve, manage intermittency on the Grid, control voltage and frequency regulation. And potentially can avoid transmission lines and distribution system upgrades.

So I'm just going to focus on a couple of things that we would like to see as what I think are fairly simple changes that the State could address to unlock some of these values. The first one is there's this idea that we have about the customer grid interface, where a battery located behind the customer meter can really only be used to reduce the customer load. If you're participating in a Demand Response Program, you can only use the capacity in that battery up to the load that the customer is using.

So if you have a battery that's capable of discharging 5 kilowatts and the Grid really needs energy at that particular time, but the customer is only using 1 kilowatt, you've basically got four kilowatts of wasted capacity. And as we deploy more and more of these distributed batteries, that's a lot of capacity that we could be using to replace power plants and transmission lines that we're not using.

So we would like to see sort of the state agencies get together and think about what is the limitation that prevents a battery from participating in, for example, the demand response option mechanism. And not being able to get credit if it discharges energy past the meter.

The second thing I think we'd like to address is simply interconnection. There needs to be a lot more streamlining. So in cases where a customer deploys a battery that's configured not to discharge, and we can do that with the switches and relays, we really think interconnection should be no more complex than simply deploying a devise or a hot tub or something that consumes energy behind the customer meter.

And then finally I'll just mention the importance of data. So as I mentioned, batteries can do a ton of things that can help utilities manage their distribution grids. But we really need access to data on what those needs are. And for it to be transparent and provided them machinery (indiscernible) of a format that third-party providers can look at and see if we can provide a less expensive solution.

So with that, I'll conclude and go to Jim.

MR. TISDALE: And let me pause you just for one second. Did you all want to ask Daman any questions before we move on?

CHAIRMAN WEISENMILLER: I'll just follow up with one. I was holding things generally, because I have some others. Yeah, actually it basically is just showing the numbers. If Tesla has data on the various value streams and the cost, let's put it in the record.

MR. FRANZ: Certainly, we can do that.

CHAIRMAN WEISENMILLER: I mean, yeah. Again, obviously there's been a long list of value streams and people have done different studies, but if you've got real data that would be fantastic.

MR. FRANZ: Yeah. We can do that.

CHAIRMAN WEISENMILLER: The other question was just to the extent we've heard about the ISO's DER Program, do you guys participate in that or why not if not?

MR. FRANZ: You're talking about the DERP? We're participating in the rulemaking, if that's what you mean, the regulatory process?

CHAIRMAN WEISENMILLER: Actually, I'm hoping people actually get into the market. Start selling something into it, as opposed to just being the rulemaking. I realize the rulemaking sets the foundation and you can participate, but --

MR. FRANZ: So this is one of those areas where the obstacle I mentioned earlier about not being able to export past the meter, a lot of the batteries that we've deployed so far are paired with solar PV systems. And so even if the customer actually has load and we have a battery and we could do load draw. Because the PV is exporting -- and it may overlap with times when you might have a capacity event called -- we're worried about basically being disqualified.

And so for products like PDR and some of the wholesale market capacity products that we might otherwise participate in, we're sort of reluctant. But we are participating in those programs with some of our own facilities just to kind of get practice and get experience. But it'd be had for us to roll them out wider to customers without some of these rules being addressed.

MR. CASEY: Yeah, Damon. I'd welcome having further discussions with you about that concern. Because at a minimum I would think there would be a way to manage what you provide and how it's dispatched around that constraint. I realize ultimately you'd like to see that constraint go away, but if it can't why can't the batteries be managed around that constraint?

So we don't have to solve it here, but I would really encourage further discussions with our DERP team and you to see what can be done there.

MR. FRANZ: Yeah. I think we would love to come up and meet with you guys, and talk about it.

MR. TISDALE: Should we continue? Great. Thank you.

Jim?

MR. BAAK: Great. My name is Jim Baak. I'm the Program Director for Grid Integration for Vote Solar, at least through the end of next week. And after which I'm going to be joining STEM's regulatory team. But my comments today are on behalf of Vote Solar.

I wanted to talk a little bit about the vision for distributed energy resources. And my concern is that the vision is somewhat myopic in that it's looking a lot at process, rather than what do we hope to achieve with distributed energy resources. There's a lot of alignment of proceedings and there's a lot of focus on some of the specific issues of integration, hosting capacity and locational net benefits. Those are all very good and I don't want to diminish the work that's been going on the working groups, which I think has been extremely valuable.

Between the stakeholders, the IOUs, the Commission and More Than Smart, I think we've done a lot of progress particularly on the Integration Capacity Analysis. We've made some progress on locational net benefits, although not to the extent that we think is necessary in order to really inform sourcing options.

But really what we're lacking, in my mind, is what do we really hope to achieve with distributed resources as resources to help California achieve its policy goals? I think if you look at it from that perspective, the barriers or the obstacles really start to come out in higher detail. And that is right now, and I think you mentioned this Chairman Weisenmiller, is that the utilities have a strong incentive to invest capital in this grid, based on the current regulatory framework.

So that's at odds with these policy goals where we're asking the utilities to forego making capital investments and instead procure third-party DER services. And that's something that's not in the interest of their shareholders. And I think until we really start to look at aligning their financial goals and objectives with the policy objectives, we're going to be increasing our regulatory oversight requirement.

And what I mean by that is if you look at Southern California Edison and all the IOUs' general rate cases you're seeing a lot of investment proposals for significant amount of grid modernization investments. Southern California Edison's Phase 1 general rate case, we've hired a consultant to take a look at it, a former utility distribution engineer. And we've identified about $4 billion worth of grid modernization investments that are related to facilitating the deployment of distributed energy resources in one form or another.

Now our analysis shows that about 2.7 billion of that 4 billion is not justified, currently. And we think it's not justified, because we don't think there's enough emphasis or process put in place to evaluate how can we deploy distributed resources in a manner to avoid those investments?

So instead of looking at and putting in bidirectional switches throughout the Grid, how can we deploy distributed energy resources to meet that need? If you've got a high potential growth of electric vehicles in an area that may be driving capacity increase on a distribution grid. Or if you've got a lot of solar PV coming in that may drive backflow across a switch, can you instead deploy energy storage? Either utility owned or third-party owned via incentives.

How can we really maximize the amount of non-wires DER alternatives? And there's sort of two different types of DER deployment that we're talking about. The directed DER deployment, which is really the focus of the DRP proceeding. And the autonomous growth of DER, which hasn't been getting as much attention. And how do we facilitate that in a manner that benefits the Grid or minimizes the impacts of that, without making a lot of grid investments? Because the more investments we make into grid infrastructure, then that creates a high revenue requirement, more fixed costs that have to be recovered from the ratepayers.

So you have a potential where you're going to have more customers self-supplying. But you're going to put more capital into the rate base that needs to be recovered. So that's going to result in higher fixed costs. Higher fixed costs that can't be avoided by DER, meaning that you're destroying the economics of DER. So instead of having a utility death spiral you have a DER death spiral.

That's my concern, is that we're going to have so much over-investment potential in the Grid that it will impact the economics of distributed energy resources in a negative way. And that's largely driven by the fact that the utilities still have a significant motivation to invest capital in the Grid in order to create shareholder value.

And if we look at this again from stepping back into what's the vision for DER, how do we want to deploy that, to me that comes into striking focus of this is something we need to address. Because the pace, in my mind of the market deployment of DER -- in other words customers buying electric vehicles, rooftop solar and battery storage systems -- is outpacing our ability to create and implement regulations to really cost effectively optimize the deployment of that DER.

So we kind of have a mismatch of timing and a mismatch of financial incentives and sort of policy goals. And I think that what we should be looking at are, and what we're not doing a lot of yet, is looking at other sourcing options. And sourcing options that may include a distribution market for DER.

We've done a lot in distribution deferral, using competitive solicitations. That's been a big focus of what we're doing in the efforts at the DRP, but there's limits to that. It takes a long time. And there's a long process to go through that. So if needs change it's harder to go through the regulatory process no matter how much we streamline that, to be able to act quickly enough to meet those needs in the most cost effective manner.

So other sourcing options, whether its tariffs or incentives or potentially market mechanisms need better and more detailed, more granular information. Like a distributional marginal cost instead of locational net benefits, which really is just intended to be indicative value to guide DER deployment for DER developers.

But we've heard the utilities say time and time again in the working group meetings that the LNBA should not be used to inform tariffs or sourcing mechanisms. And we need to get to the point where we can actually develop that type of information and the data platform to be able to get access to that information in a timely manner to inform DER deployment, to inform DER developers, who can then deploy those resources.

And then you don't have as much of a concern for contingency. If you signed a PPO with somebody and they don't show up what happens then? Well, do you go with the traditional utility investment or do you go back to the market? Do you have enough time to go back to the market?

As opposed to having a distribution market where you have a price that's transparent and it's published whoever the lowest bidder is. And just like an ISO or are RTO you have somebody bidding in for that. It's much more dynamic and it supports more DER.

And again if the goal is to animate the market for DER, deploy DER in a cost-effective manner, create customer choice then I think the approach that we're taking now is very limited. And it doesn't have that bigger, longer-term vision that I think we need to have in order to really achieve what I believe is truly animating the market for DER and leveraging these resources to meet the State's very ambitious climate goals.

And so with that, I'll leave it to --

CHAIRMAN WEISENMILLER: No, that was good. I was going to say you got the -- my answer to you was going to be, hey look, we're all focused on greenhouse gas emissions. We're focused on the climate goals. If this is a tool to address those it gets interesting. If it's just a hobby -- you know, it's got to focus back on that. Climate is, as the Governor says, the existential problem of the day.

Now having said that you also have to look at the utility structure, and if you look at again going back to the en banc it's the same thing as I said there.

I mean, the good news is we're not a rate case. We're not doing rate cases, so that's not my headache. But having said that it's back to Alfred Kahn, what's the utility function? It's where there are economies of scale. And where are the competitive markets is where there's not economies of scale. So I mean you have to look at that philosophical how does that fit in?

And obviously, one of the things that (indiscernible) initially, utilities are not necessarily known as innovative entities. But having said so trying to get some innovative entities, trying to get some other sources of capital in. But as I said, it's something which has to connect back to climate change. You could really get me interested in it.

MR. BAAK: And that's an element of the evaluation of is the DER solution, or the alternative, how does that impact our climate goals? And that has to be part of that evaluation.

And I look at what's going on in New York and they've created a vision that really establishes a role for utilities. And that same thing I think we're lacking here is that regulatory certainty. And I don't fault the utilities, because they need that regulatory certainty of what is the role of the utilities moving forward? And how do they actually ensure that they are providing value to their shareholders? I think we have to have that discussion. We have to have that evaluation.

You know, what they lack in New York is a lot of what we're doing in California. They don't have the AMI data. They don't have a lot of the software tools. They don't have a lot of the data that we have here. And we've got I think a world-leading effort to try and get that very granular locational data. And combine it to inform this process, but we sort of lack that longer-term bigger, broader vision of where do we go with this? What is the role for utilities? What is the role for third-party aggregators? What is the role for consumers in this?

That to me is very cloudy. And I think we need to have more policy certainty for all players in order to really maximize net benefits. Otherwise, we're going to continue to just be trying to catch up with the autonomous growth of DER and we're never going to be able to do that by trying to get regulations to match the pace of market evolution.

MR. TISDALE: May I make a suggestion?

MR. BAAK: Sure.

MR. TISDALE: I bet that everybody at this panel has something to say about the clarity of the vision for DER and the impact of the vision statements and the roadmaps that we have on investor certainty and on the company's bottom line.

I was going to suggest that let's hear from Carmen. And then come back and ask an overarching question of all the panelists about the clarity of the vision as we've heard here in the documents today. And then the in ongoing action plan and have a little bit broader conversation on the regs.

CHAIRMAN WEISENMILLER: That's really good.

I guess the other thing I'd want to throw out is at lease Ron Nichols, I believe in January, threw out the notion that Edison wanted to become the Distribution System Operator. I've no idea where PG&E is on that or how anyone at the piano would react, but that would be another piece I'd like to hear.

MR. TISDALE: Indeed.

Carmen, thank you. And I think we have some slides for Carmen. Great, they're coming up.

MS. GARRALAGA: Okay. Good afternoon. My name is Carmen Garralaga. I work for SMA America and my presentation today is about Role of the Smart Inverters in DER Integration. So next slide, please.

So for those who don't know SMA, we are a solar inverter manufacturer. Our headquarters are based in Germany, so we are German engineering in solar inverters. The headquarters in the U.S. are located near Sacramento, in Rocklin. And we are represented in 20 countries, but we have inverters installed worldwide. So we have over 55 gigawatts of solar inverters worldwide. We provide all sorts of solar inverters from utility scale, commercial, residential and also for storage systems. In North America we have over 10 gigawatts installed and a large part is in California.

So we have been recognized many times for different organizations. Recently, we were awarded with the Inter Solar Award. And one of the key things is that we operate the largest PV monitoring database, because we can monitor all these inverters. So next slide.

So why use smart inverters. Well, inverters are basically the interface to the Grid, so they will convert the DC power from the solar system into AC power. And initially they were just doing these conversions of DC to AC. But now with the high integration with renewal energies, we need to have more functionalities. So solar inverters can have functions for grid management, so that they can support the Grid by changing their configuration. They can react on the different grid situations like they can reduce the active power. They can provide reactive power, active power.

Also they work -- like in residential systems they can have energy management functionalities. So you can see from your smart phone if you have good energy production from your solar system. And you can switch on some loads for instance: the dishwasher, the washing machine. So the consumer can really check what is going on in the solar system.

They also, in residential systems and also in the utility scale systems, we can also provide storage. So we can put battery systems connected to the inverters and they can also react depending on the grid conditions. Last, but not least, they can monitor all the plants. They can monitor the batteries.

And also you can remotely control them. So like in some cases, in some utilities are also in control of the solar inverters. They can send commands. They can send curtailing commands to reduce active power. They can change the power factor, reactive power, so depending on the utility requirements.

Here, we also see another example for utility scale systems. They can also receive commands externally. And the inverters are really fast, so they can react quickly in a matter of milliseconds or seconds they can change quickly the active or reactive power they can provide. Next slide.

So how we are participating in this Action Plan? We have been working for many years in different working groups. So representatives from SMA, here in the U.S. and also in Germany, they are participating in these working groups for known inverter grid integration issues.

We are also in the California Rule 21 working groups, to give recommendations to explain what the inverter are capable of doing and what should be used or not depending on the requirements of the Grid. Also, the Smart Inverter Working Group that this morning they were talking about; the HECO Rule 14, which is for Hawaii; and other working groups like for communications, like the IEEE 2030. So these groups are also to start discussing about what communication protocols can be used to control the DER.

Other things that we also do, we always try to be close to the utilities, so we can understand their problems. And also we do that in different countries. So we try to work always with local utilities in understanding the problems and trying to propose solutions with solar inverters, and also now with the storage inverters.

Another group that we were taking part of is the APS Solar Partner Program (indiscernible) public services. So this was a pilot program that APS was renting homeowner rooftops. And they were using our inverters to see the different functions of the grid management functionalities of the inverters, so how they were able to provide these reactive power or power factor to the Grid. And the second phase will be to integrate the storage as part of the program. Next slide.

So as we also were seeing this morning, the Action Plan has now a deadline on September 7th. And Phase 1 will be deployed, so the inverters need to comply with Rule 21. So with this Rule 21 the inverters have different functionalities, so these are listed here like anti-islanding. The inverters can detect in case there is some island situation and they will disconnect from the Grid. They have specific voltage ride through settings, and frequency ride through settings, which means the inverters are all the time monitoring the voltage and the frequency of the Grid.

And they can stay connected or disconnect, depending on what is required. And also we put the thresholds and the timing when they need to stay connected and when they need to disconnect.

Also, an interesting part is the Dynamic Volt/Var operation. So depending on the voltage of the Grid, the inverters can provide some reactive power to support the Grid. This way they try to keep the Grid on and they try to improve the quality of the Grid.

And also they can have some ramp rates and soft-start methods, so they inject the current into the Grid with some rate, so it is not solid. It is in a staggered manner.

Finally, they can also have some response depending on the frequency. Like if the frequency goes very high, they can reduce the power coming from the solar inverters. Next slide.

So this is the last slide I have. As future steps, we are also working on different things like communications. These will be Phase 2 and 3, how inverters can monitor and can be remotely controlled by the utilities, or different types of control. Also how you can forecast also the resource, how you can what's going to be produced in the next hours.

And we are working also in battery integration, so adding batteries, it can help to the Grid. So there is no need to update sometimes the local grid. It can support the Grid, like in some cases if there are problems with the frequency there are very interesting frequency controls.

For instance, right now in the UK they are really working on 150 megawatt projects with our inverters to install this year, batteries. And to support the Grid and keep the frequency up there within the range it needs to be, because they really have problems with the frequency in the UK.

Finally, also the battery integration can support the growth of renewable energies in a sustainable way. So I think that's all from my presentation.

MR. TISDALE: Thank you, Carmen. We appreciate your presentation.

I would suggest that if there's questions for Carmen, on the role of smart inverters let's have those and then we can reassess some of the broader themes, if you would like?

MR. CASEY: Thanks. Carmen, a great presentation. And let me just say the California ISO has had the opportunity to work with SMA on some inverter issues and just want to comment what a great partnership we've had with you. And your company has been very responsive to the issues we've identified, so we truly appreciate that.

MS. GARRALAGA: Thanks.

MR. CASEY: And I think you're spot on in terms of the capability of the inverter technology to provide central grid services. And Commissioner Hochschild mentioned earlier the pilot we did for solar and NREL. Essentially putting a 300 megawatt solar project through its paces, in terms of its ability to provide the services you mentioned: reactive power support, frequency regulation, response to frequency disturbances.

And the bottom line is the technology is amazing.

It outperforms any conventional resource. So as we look at kind of the next generation of renewables and how we go about procuring those, we need to make sure we secure those grid capability services. Because otherwise we're going to still be dependent on conventional plants to provide them.

So I think the future is quite bright for the inverters to really, along with the advanced control systems, to really step up to provide those services. Even in the evening, you can leverage inverter technology to provide voltage regulation and the like, so it's really quite encouraging.

MS. GARRALAGA: Yeah. Thank you.

MR. BAKER: Thank you for your presentation, just a question. I'm somewhat a novice in smart inverters. And I'm wondering the extent to which there are already smart inverters deployed out there in the California system that have some of these latent capabilities, these Phase 1 capabilities, that just aren't switched on yet. How big of a scale is that really?

MS. GARRALAGA: Yeah, so most of the inverters which are currently connected, they can be adapted to the new Rule 21. Sometimes we just need to do some firmware updates, so they can change the settings to the new settings, which need to be now deployed in September.

And the thing is in our inverters they've had these capabilities for a long time already. We are a German manufacturer, as I said. And in Germany they were requesting this sort of regulations some years ago already. So they just need to be activated. Some of them might be slightly different than the real need that we need to activate, like some thresholds might be slightly different for older units. But most of them can be activated and shouldn't be so difficult.

Actually, right now we are also trying to update some settings in our inverters in plants in California. Because of the Rule 21, so we are trying to change for the utility scale plants, frequency settings to better measure the frequency of the Grid, so we stay connected for a longer time.

MR. CASEY: Simon, if I might? I also think that it does vary depending on the inverter manufacturer and the project, because there are additional costs to securing some of those capabilities, especially with the control systems as well. And so I think it's important that there's good alignment with the utilities and the PUC on the importance of securing that capability even if it has an incremental cost, because we can leverage it down the road.

And there's also an opportunity cost. If you are providing upward regulation management or you're being held back to provide frequency capability, it means you're not producing real energy. So do the power purchase agreements allow for that kind of use of the resource. And I think those are all things we have to look at.

MR. BAKER: Yeah, just to follow on to that a little bit. So how are you structured in terms of your communication networks with your customer base of customers that have installed your technology here in California? I ask the question in terms of like how easy would it be to do like sort of a large scale outreach upgrade to existing installed systems to come up to you know the new Phase 1 inverter standards?

And there may be a cost associated with that, of course, but I'm just thinking there could be a role for that. And as we have looked to some of the utility planning efforts and any parts of their systems that might, for example, be experiencing voltage issues. Might a strategy be to go out and basically just try to upgrade existing smart inverters, and activate those latent capabilities to the Phase 1 standard. Might that be a cost effective alternative to maybe a traditional utility infrastructure alternative?

MS. GARRALAGA: Yeah. As I was saying we are currently doing this kind of upgrades for larger plants, so currently we are updating plants, which are over 20 megawatts. And the ones which are connected to the distribution line, we are updating then to the Rule 21.

Of course, larger plants are easier, in terms of they always have some communication systems. For residential inverters, that might be more complicated. Sometimes they don't have access to a network and we are not really controlling those plants. Larger ones we usually have more visibility, so we always contact customers and they provide us the network dictates and we can do upgrades.

MR. TISDALE: Good. Thank you for those answers, Carmen.

Would we like to have a little bit more time in a broader discussion or are you all satisfied?

CHAIRMAN WEISENMILLER: No, let's hit your two, the question you had and the question I had. And see how far -- I'm sure we'll lose everyone at some stage, but let's at least answer those two questions.

MR. TISDALE: Perfect, so the way I wanted to reset the theme that Jim had brought up was that one of the main goals with the various action plans and roadmaps, some of which have been exhibited and updated today, is to provide stakeholders and your investors greater certainty in the direction of California's policy.

And I wanted to just ask an open question of all of the participants in this panel how's that going? How effective has the plans been toward that end? Is California's vision for DER clear and what improvements do you think could be made going forward?

Mark, would you like to begin?

MR. ESGUERRA: I'll take a start at that. So again, most of my efforts have been on the planning and the wholesale interconnection portion. And as I mentioned, there's three tracks.

Some other thoughts that we've had was more integration with the rates track. There's been a lot of discussion about how the planning track will tie in with the wholesale interconnection track and in some earlier discussions I've covered where that's at, so it's started to become a little bit more visible. But seeing can we integrate more make it a little bit more transparent on how the rates track could better inform the planning track and wholesale track and vice versa. I think that's one area we'd like to see maybe some more opportunities there.

The other is more clear linkage to the IRP. I mean, I think Commissioner Weisenmiller had brought up the IRP and the environmental goals. We firmly believe that the planning should start really there at the resource level. Like what resource mix do we need from an optimization perspective, for environmental goals?

And then the link back to the distribution side would be with these different portfolios of potential optimization and how to help achieve those environmental goals. What's the impact? How does it integrate with the T&D grids? Is there going to be certain investments on certain portfolios? How does that factor in? Does it defer certain investments that utilities are seeing, so to Jim's point.

So with the environmental goal first in mind, how does it flow down as well as how are rates going to be kind of interwoven in this? I know there's a lot of work there, but I'm really intimately involved in the planning in the wholesale track. And I just haven't seen as clear an alignment or linkage there.

MR. FRANZ: Yeah, I would agree with your plan on rates. And I'll get back to you in a second, but I just want to address the broader question of how are we doing in terms of moving towards markets for DERs and assuring investor certainty.

And I think coming from a company, SolarCity, that was very focused on the regulatory side of moving to a larger company, Tesla, who recently purchased SolarCity, it's very much a consumer-focused product manufacturing company. You know, I think that there is a desire to try to find some sort of certainty for the products we provide.

So for example, if we are generating energy behind the customer meter and storing that energy. And not exporting to the Grid and basically just reducing the customer's consumption of electricity, I think we would like to have some certainty that there's some sort of protection that the regulatory framework is not going to reach behind the customer meter and impose kind of charges and fees that further erode the value proposition. Because it's very hard to plan a long-term business if you can't even have certainty that you're going to have some kind of protection from your value stream being eroded.

But I think that where that kind of relates to rates, is that in order to kind of achieve that operating space where we can kind of deploy products that serve customer and grid needs I think rates really need to align with the cost causation. And one of the things that having advanced DERs that are very responsive and networked, is that to the point that Simon made earlier, is that demand response really needs to be almost invisible to the customer.

Having products like battery storage and smart inverters and other like smart appliances that allow for immediate response to rates allows for the customer response to be seamless, so the customer doesn't even know that the house has responded to the rates. And it allows the rates that can be almost perfectly aligned with cost causation. So instead of having a time-of-use rate where it's 3:00 to 9:00 every single day, maybe one day the peak is 4:00 to 6:00. And maybe one day the peak is 5:00 to 7:00. You can have that sort of shifting rate that aligns better with the actual cost of providing the electricity.

And I think what that will do is allow for things like in the Title 24 Zero Net Home Regulation, you can have battery storage and other load-shifting technologies that can be installed. And can be put on a rate where they're responding to the utility signal. And the regulator can be confident that those appliances are going to be operating in a way that actually maximizes their value to the Grid and their greenhouse gas reduction potential.

Because I think right now what your folks who work on Title 24 are struggling with is we can put like batteries and load-shifting devises in homes, but how do we know there's actually going to be operating in that greenhouse gas optimal way? And I think the rates are kind of a key to that.

MR. BAAK: I'm going to build on my earlier comments. I think in terms of how it's going now, we have a real concern about the grid modernization piece and where this is going in the general rate cases. And there's a real concern for overbuilding and creating some stranded investments, because we don't have the processes yet in place to really fully evaluate the non-wire alternatives.

And not just for distribution investment deferral, but to support autonomous DER growth. I think I heard in the presentation this morning on the DER Action Plan, I think it was Gabe that made the statement something like that we need to see which investments in the Grid would be necessary to facilitate autonomous growth of DER.

Well, in addition to that, we need to look at are there DER alternatives that can support autonomous DER growth? In other words, can you direct a storage or demand response deployment in an area where you have potentially high growth of DER to avoid that?

And we don't have the regulatory oversight yet in place to be able to evaluate did the utility look at non-wires alternatives? And that's a new function for utilities as well and that's something that we think needs stakeholder engagement.

So we're still debating whether or not the Distribution Planning Advisory Group should have market participants or not. And we believe it should, because there's a lot of new technology and new services. A lot of this is very fresh. It's new. The utilities may not have all the information about what the services and capabilities of demand response are. So we need to have that in order to be able to evaluate what those capabilities are.

You don't want industry stakeholders on anything that's looking at procurement, but you need to have that expertise available. And you need to have the expertise at the Commission, in order to be able to really evaluate is there a non-wires alternative? You need to have the data there. You need to have the process there in place. And that's not there.

The other thing is the locational net benefits analysis, in our opinion, is not ready for prime time. It's using indicative values. We've heard that it's not really designed, from the utilities prospective to inform sourcing options. It's really to just provide direction indication to DER developers. But we need something that gets to very granular, what is the value? What is the net benefit, the avoided cost of this particular location on the Grid? And what are the optimal portfolio of resources that could be deployed in order to meet that need?

We're not there and I think we need to get to a distributional marginal price. And I think the utilities all have software from the vendor that has the ability to get a distributional marginal price, but we haven't really explored that very much. And we to explore that.

I'll also agree that we need to better inform the integrated resources planning process, so that we can really fully value the full benefits of distributed resources on the system, the transmission grid, the bulk system as well as the distribution system. That's an important piece of that.

And to inform the NEM 3.0, the next iteration of this. And that's really going to be difficult until we get a better understanding of the true value and the full value stack of solar and other forms of DER, to be able to really inform the NEM 3.0. And I don't think we're ready for that yet and it's getting closer and closer to that.

So the last piece is really the sourcing. We've started talking about distribution deferral. We've looked at doing RFOs for procurement. But we haven't really looked at other sourcing options whether it's tariffs, incentives. And I really think we need to start exploring the options of markets, distribution market prices.

We've got some innovative tariffs that San Diego Gas & Electric, for instance, deployed with their electric vehicle program; a day-ahead price for their EV charging program. That's very innovative. We want to see more of that kind of innovative sourcing option. But we have to have an exploration of what are the potential options for sourcing these DER.

We're doing a better job of identifying where the locations are. We can get values for that. But then how do we actually source the DER in those areas to know that we can have DER to provide those resources when they're needed. So that we don't have any gap between the utility's planning cycle to do an alternative conventional upgrade to the Grid. We need to be able to do that. And then we're not there yet.

And again to me this is really based on the fact that we don't have -- we haven't begun exploring the regulatory framework changes that would align the utilities' business model with these policy goals.

MR. TISDALE: Thank you, Jim.

Carmen, would you like to comment on the question, is California's vision for smart inverters clear to you and your investors?

MS. GARRALAGA: Okay. So from the inverters' point of view the working groups have been very effective. And they have been successful, because there has an agreement on what is needed. And it has an agreement on what we can do from the inverter.

I think we need to continue working on these working groups to continue with the next two phases and achieve an agreement on those phases too, on communications and storage as well.

And how to do that? Well, we can always see what other markets are doing. We don't need really to reinvent the wheel, so we can follow international standards for communications maybe or things like this. But so far it's been successful, the agreement we achieve.

MR. TISDALE: Thank you.

Chairman?

CHAIRMAN WEISENMILLER: No, I would suggest again looking for people in their comments, because I think we're probably at that stage where we can see if we have public comments, it would be good to think a little bit about priorities.

Those of us who've been following the PUC for years know that things go relatively slowly, but also carefully. And something that has to be phased -- so anyway I'm just saying if you're thinking about any number of times when we've tried for really big changes -- it ends up going through this process, which everything takes a long time. And in the meantime the questions is what happens with things you should be investing in while you're going through that process to get to the ultimate end state. And then you can get into some real traps.

So somehow you have to figure out what are the most important pieces of this puzzle in some sort of sequential fashion? How do you resolve those?

And I would also note that typically looking at the Commission, the parties can settle issues realizing that there's some issues, which are probably going to have to be litigated. But if there's anything you can settle and get off the plate you're more likely again to get there wherever there is, faster than if you're going to litigate every single issues through this process.

But again certainly looking for suggestions from folks are what are the major things that we can do to move forward on these topics?

And again thinking a little bit about the things the three of you can step outside and just get off the plate with Matt and take back to the Commission. As opposed to things where you want an ALJ and frankly you never know what the ALJ is going to decide on this type of complicated technical issue, right?

So you've got a certain amount of risk for your clients that at the end of the day, you're going to win on the stuff that doesn't matter and lose on the big stuff if you take a fully litigated approach. So make their jobs easier. (Laughter.)

MR. TISDALE: Great. Well, thank you panelists for being here today, for your time, for your perspective.

And with that we'll turn it back over to CEC.

CHAIRMAN WEISENMILLER: Thanks. Thanks. Actually I'm sorry, I just wanted to make sure everyone else -- yeah. Okay.

So I think we're at that stage of public comment. And just to remind everyone if you're in the room we're looking for a blue card or you can line up. But ultimately our court reporter's going to want to know who you are.

And at this point, I have one blue card from Udi?

MR. MERHAV: Yes, sir.

CHAIRMAN WEISENMILLER: Please come on up and introduce yourself and make sure you give a business card to the court reporter. It's the dais, yeah, right up there.

MR. MERHAV: (Indiscernible) like so?

CHAIRMAN WEISENMILLER: Yes.

MR. MERHAV: Thank you Mr. Chairman. My name is Udi Merhav. I'm the founder and CEO of energyOrbit. We are a software company. We help utilities and third parties implement energy efficiency programs.

And one of the mantras that I subscribe to is that today's energy efficiency customer is tomorrow's DER customer. And the question that I put on the blue card is what considerations are there, if any at this point, in terms of leveraging the existing energy efficiency activities that have been taking place to date to create the synergies and to further increase and accelerate adoptions of DERs around the State of California?

That's what I have. Thank you very much.

CHAIRMAN WEISENMILLER: Well, actually let me ink -- we'll get to this point soon about when the written comments are due, but we would certainly love to hear from you if you have specific suggestions on that topic.

MR. MERHAV: So the suggestions also --

CHAIRMAN WEISENMILLER: In your written comments, yeah but you can go on. You still have a couple of minutes, you can go on now.

MR. MERHAV: Okay, so the way we see it and we've been doing this for ten years now. I think that one of the few times where a utility has the opportunity to strike a meaningful relationship with a ratepayer -- I think it's become more politically correct to call them customers -- but nonetheless that is when an energy efficiency project takes place. I think that is one of the few times, as I said before, where a utility has the opportunity to create a meaningful relationship with a customer. The question is why do you do this?

So you, whether it's C&I or residential, you went there and you installed energy efficiency measures. You are done with the project. What's next? How do you further leverage this to introduce DERs around the nation, or around the state at this point?

So for example, I live in Sebastopol. I can see in the future Sebastopol becoming a microgrid. Okay. If it becomes a microgrid how do you go out and you locate those customers that already have a predisposition to participate in their models, because they're already on board in terms of energy efficiency? So you may have clusters of storage, public storage facilities in neighborhoods. How do you very quickly get the buy-in from residents to actually have a public storage facility planted somewhere in their midst?

How do you get those folks to further participate with in terms of -- you know, by the way I have to admit I did not realize I actually came here with my EV, with my Volt, in 238 miles. I was able to do this. That one day I may have the option not just to suck juice from the Grid, but actually use my battery to put some back. Things like this. I hope you get my drift.

CHAIRMAN WEISENMILLER: Yeah, no certainly in public comment we generally don't have the back and forth. But I was going to say certainly if you sold energy efficiency -- Simon and I were talking at lunch -- if you provided an HVAC upgrade for someone it's like well, can you sell them the rest of the energy efficiency portfolio? And it's probably no secret that Tesla having sold someone a PV system would be happy to sell them the battery or if they bought a car to sell the PV and the batteries. So again, upselling is sort of a classic approach.

MR. MERHAV: Upselling, upeducating.

CHAIRMAN WEISENMILLER: Yeah. Thank you.

MR. MERHAV: Thank you very much.

CHAIRMAN WEISENMILLER: Anyone else in the room?

(No audible response.)

Anyone on the line?

MS. RAITT: Yes, Allison Johnson on WebEx. Go ahead.

CHAIRMAN WEISENMILLER: Please go ahead.

MS. JOHNSON: Hi, thank you. This is Allison Johnson with the Interstate Renewable Energy Council. I really appreciate you putting together this workshop and the wide range of presentations we've heard today.

For those of you not familiar with us, IREC is an organization that works nationally to encourage states to adopt policies and regulatory reforms that expand access to and streamline integration of DERs to optimize the use of their many benefits. I just wanted to quickly echo two points that Jim Baak made about priorities and about the long-term vision for incorporating DERs into the Grid.

First, we see leveraging the full range of benefits of DERs as a top priority. And so it's really important that screening for DER options and alternatives precede decisions to make new capital investments. And so that's tied closely to the second point that we agree that the utility business model remains a significant barrier to achieving policy goals.

We recognize that we're in a period of significant change. And that reaching alignment on this particular issue is going to take a lot of time. So in the short term, we see the best fix as building more transparency into the planning process. So stakeholders can identify opportunities where we can rely more heavily on DERs and access a wider range of their benefits.

So I appreciate the direction that California is moving. And that the State continues to be one of the key leaders in this. And I'm looking forward to seeing next steps from you. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

Anyone else?

MS. RAITT: No one else on WebEx.

CHAIRMAN WEISENMILLER: Okay. Let me turn to my fellow panelists and dais members and see if anyone else wants to do a wrap-up comment?

Mr. CASEY: Well, I would say it was a really excellent discussion today. I think I learned a lot about where we're at and all these very disbursed efforts going on, on DER. So I appreciate all the participation from the panelists and the audience and look forward to following it going forward.

CHAIRMAN WEISENMILLER: Simon?

MR. BAKER: Likewise, I very appreciated the day and the content. I think it was an indicator of great interest in this topic. The fact that we were kind of behind the clock the whole day and we had a lot of discussion from the dais and I appreciate everybody's input.

COMMISSIONER DOUGLAS: And I'll just pile on to the thanks for the great panel. Thank you.

CHAIRMAN WEISENMILLER: Yeah.

COMMISSIONER DOUGLAS: It was a great day, a series of panels.

CHAIRMAN WEISENMILLER: I want to thank everyone for their participation today. And again it's an important topic and it covered a lot of aground. And again Heather's going to tell you when written comments are due, which we're looking forward to.

MS. RAITT: Yep, written comments are due Thursday, July 13th, two weeks from today.

CHAIRMAN WEISENMILLER: Okay. So again thanks. This meeting is adjourned.

(The workshop was adjourned at 4:04 P.M.)

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 19th day of July, 2017.

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Myra Severtson
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