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BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of:	) Docket No. 18-IEPR-06
	)
2018 Integrated Energy Policy	) Integrated Renewable
Report Update (*2018 IEPR Update*)	) Energy

IEPR Commissioner Workshop on
Renewable Integration and Electric System Flexibility

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

WEDNESDAY, JUNE 20, 2018
10:03 A.M.

Reported by:
Julie Link

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Sabrina Butler, San Diego Gas & Electric
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Public Comment
1. Steve Uhler
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I N D E X

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P R O C E E D I N G S

JUNE 20, 2018 10:03 a.m.

MS. RAITT: Welcome to today's IEPR Workshop on Renewable Integration and System Flexibility. I'm Heather Raitt, the Program Manager for the IEPR. I'll go over our usual housekeeping items. If there's an emergency and we need to exit the building, please follow staff to Roosevelt Park, which is across the street, diagonal to the building.

And our meeting is being broadcast through our Web-Ex Conferencing System and we'll have an audio recording posted on our website in about a week, and a written transcript in about a month. We do have a very full agenda, with lots of wonderful presentations.

And so we'll be giving folks reminders on timing, and Kaitlin will just put a little sign up when you have two minutes left and when time is up. At the end of the day we have an opportunity for public comments.

We'll limit those to three minutes per people -- per person, and we'll take folks in the room first, and then on Web-Ex and on the phone. And if you want to -- if you're in the room and you want to make a comment, go ahead and fill out a blue card and give it to me, or Public Advisors in the back of the room.

Meeting materials are all posted -- yeah -- nearly all posted on our website, and they're available in hard copy at the entrance to the hearing room. And written comments are welcome and they will be due on July 5th, and the notice gives you all the information for providing written comments.

So with that, I'll turn it over to the Commissioners.

CHAIR WEISENMILLER: Good morning. This is a follow-up to a Workshop we had last year. And in the Workshop last year we looked at what the operating statistics were for the CAL ISO, a pretty clear message of, you know, basically the duck belly getting lower, ramps getting steeper.

And at the same time we then looked at a wide range of options of what we could do to sort of address some of the renewable integration issues. But at that point it didn't appear that any of them were anything but conceptual or experimental.

You know, even one of the more interesting slides from the last year's IEPR was that our demand responsibilities have gone down, you know, I mean, in spite of massive pushes to make it go up. So today's effort, I really want to focus on not just the options, but what are we doing to actually implement the options going forward.

COMMISSIONER HOCHSCHILD: Well, good morning, everyone, and thank you to the Chair for his leadership on this issue, and for staff and stakeholders for organizing and attending this morning.

Just to set the stage, I think many of you probably saw the article in the Wall Street Journal last week showing basically annual spending on renewables is now about 300 billion, and all fossil and all nukes combined are about 150 billion.

So the trend really is towards renewables, and the question is really how do we make that work and how do we successfully integrate. And I think the main message of the year and of the era I think is that everybody and every device, every project has to be a good citizen of the grid and work to make the grid stable and successful.

And I think there's a lot to be done in this area, and I really appreciate, again, the Chair's leadership on this, this effort.

COMMISSIONER DOUGLAS: Yeah. I'll just add, I'm delighted to be here, and obviously, following these issues closely, as well, and very much looking forward to going from concept to implementation and deployment. Thanks.

MS. RAITT: Great. So our first speaker is Clyde Loutan, from the California Independent System Operator.

MR. LOUTAN: Good morning. Thanks. Once again, my name is Clyde Loutan. I work at the California ISO, and basically in charge of Renewables Integration to the technical studies. Also, I get involved in looking at the system performance on a minute by minute basis to see where it is we have control performance issues.

So with that -- this one. Okay. I'll talk a little about the status of the system right now, some of the operational challenges we see, some of the opportunities, solutions and then open this up for questions.

So some of you may have seen this. We all know that the grid is going through a major transformation right now. And each one of these we can plan on at least a day -- each one of these green boxes.

But basically, what I'm going to cover today is really the 33 percent RPS target. Right now, where we are in terms of renewables, what it is we see on the grid, again, so many challenges and how we plan to deal with some of these operational challenges.

So before we really get started, we have some pretty interesting days, starting with peak last year, September 1st, and then we had three interesting days this year I'd like to talk about, so we can see, again, some of the challenges we have.

Now, a lot of us have seen this curve in the past. It's still valid, and so many things, you know, we look at this curve, but it is -- a lot of folks do not really understand what the message this curve tries to convey.

So again, each one of these curve is really the net load, which is your load minus wind production, minus solar production. And as you can see, back in 2012, 2013 time frame, and it was pretty plant. It was pretty easy to predict.

Then as more and more solar came on we had anticipated the belly of this duck to drop by about 12,000 megawatts by 2020. When we initially did this one of the things we completely under-forecasted was the growth in behind-the-meter rooftop PV.

So as you can see, right now we're about four years ahead of our schedule. When we presented this last year, when we looked at the ramps, the three-hour ramps we presented was 12,960 megawatts, and we thought that was low.

In a little over a year you can see this here, back in March, we saw a ramp almost 15,000 megawatts, a three-hour ramp, and that's huge. And one of the biggest challenges is that net load, the belly of this duck.

As I said, we had anticipated this dropping to 12,000 megawatts by 2020. When we presented this last year it was a little over 9,000 megawatts and in less than a year it dropped to 7,000 megawatts, 7149 megawatts.

Now, why is this an issue? So when you start thinking about California and the diverse resource mix, what happens is when you start looking at what makes up the generation portfolio up to that minimum net load, so when you look at your two nuclear plants and your geothermal and your biomass, your biogas, running river hydros, CHPs, you're pretty close to about 8,000 megawatts.

So when the net load drops anywhere below 10,000 megawatts we start to see operational challenges in terms of negative prices, we started to see things like oversupply on the system. Then when you think about you have a huge ramp coming in, as you know, during sunset, you can see how difficult it is to commit resources to meet that ramp when you're already in an oversupply situation.

So essentially, what I'm trying to convey here is during a weekend when the net load drops below 10,000 megawatts, you need to cautiously, you know, commit your faster ramp in resources to meet this huge ramp that's coming at you on evenings.

So the alternative is, you know, unable to meet this peak during some time periods. So again, we this huge ramp increasing again. This year it was 14,777 megawatts; deeper belly. It's a concern. And then last year with the amount of hydro we had we started to see a new problem emerge, which is during sunrise.

Now, during sunrise what we saw is the solar was coming up in some cases twice as fast as the load was increasing. Now, when that happens it causes, you know, system frequency to go high. It causes prices to go negative, and a control problem.

So when I say a control problem, as a balancing authority we have an obligation to help control the connection frequency, and we do this on a minute-by-minute basis. Even though we dispatch units through automatic generation control every four seconds, we do a calculation every minute to see how well we control inter connection frequency.

So these are the three things, you know, that Doug really tried to convey, one, steep ramps, second, how low the belly is going to drop, which shows the potential for oversupply, and then now, solar coming up so fast during sunrise we started to see an additional problem.

And then when you take an overall look of the duck, it really conveys the need for flexibly capacity on the system. So with that, on September 1st last year we peaked, and we peaked at 50,116 megawatts.

When you look at this plat, the black curve is really your load on the system. The dash red is net load. So we still peak right around four -- between four and five, and that has been the case for a long, long time, because California is primarily driven by air-conditioner loads during the summer months.

So you can see what happens now. Now, when you peak right around 4:00 o'clock, or between 4:00 and 5:00, the net load -- or the solar side's dropping off and the net load still increases. So what happened September 1st is we started to see now, and on some more days during the summer months, is that peak extends to about three hours after your peak.

So even though the peak dropped off by roughly 3,000 megawatts, we lost about 7200 megawatts of solar. This is expected to get even, you know, worse as more and more renewables come onto the grid. So sustaining this peak after your true load peak is now a challenge.

We were able to get a lot of that -- or meet a lot of this excess peak or should I say peak shift as the solar dropped off from the interties. One of the concerns we have right now is if this was a hot day throughout the west, then getting this excess energy from neighboring balancing authorities could be a challenge.

On this day it was cool along the coast. So we were able to get energy interties. And when you look at this plat also you can see meeting peak demand we rely a lot on the thermal resources, hydro resources and the interchange today.

What's interesting on this plat, too, is we could not rely on the wind to help any meeting this peak. So looking at a second interesting day here, this is when our net load dropped to 7149 megawatts. Again, this was February 18th, and we had a lot of wind and a lot of solar on the system during that day.

And when you look at the red area on the very top, this is how much energy we curtailed, because we had oversupply situations; the prices went negative. And some people, you know, keep asking, well, how come you guys still had energy coming in on the ties when you have negative prices and we were in an oversupply situation.

Well, when you start thinking about entities within California, they have jointly owned units outside California, like Palo Verde. It's jointly owned by entities within California. You got Hoover. And then we got about 2500 megawatts of contracts for renewables from entities in-state with renewables out of state.

So most of this energy will come in real time when you'll see solar is producing or wind is producing depends on the reason why you'd see flows coming in, even though you have an oversupply situation on some days.

Again, on this day we had a lot of wind. We had a lot of solar. And this three-hour ramp following this minimum net load, it's a lot. It was about 1300 -- almost 13,600 megawatts in three hours. Again, when your minimum load is this low, when you look at committed resources internally to meet that ramp, it's something that you really cannot do, because you aggravate that oversupply situation.

So when you look on this day, we had almost 62 percent of the energy coming in on the ties to help meet this three-hour ramp. So this is something we need to closely look at. How are we going to meet these huge ramps, which is expected to increase, you know, as more and more renewables come onto the system, primarily solar.

When you think about rooftop PV, it's not really a one-for-one, but the rooftop PV addition lowers the black line, which is your load, and it ultimately impacts net load that we see on the system from a transmission perspective.

One tidbit here is try to control the grid, a thing I'd covered out in about two slides down. And the last plat I wanted to show is when we experienced the largest three-hour ramp, which was 14,777.

On this day, again, we could not rely on the wind. When you look at it, the wind was practically nothing. And this was way back in March. And some folks think, well, only on hot days you don't see the wind blowing.

Well, this was a good example where, again, we have to rely a lot on the inter ties to help meet this ramp. Now, when the net load is high, like in this case it was about 10,000 megawatts, you could commit some dispatchable resources.

So you can see we did commit some thermal plants to help with that ramp. But when that net load drops like the previous slide, when it drops really low, it's difficult to commit resources and you have to rely more on the ties to help meet this three-hour ramp on evenings.

Again, looking at this a different way, on this plot, this is page 9, when you're looking at the red dots, those are really the peak that we saw on those days. So looking at these three days we started to see now, in the old days we had, you know, 10-12 to meet the peak demand on a day.

So starting from about 4:00 a.m., whenever you peaked you had a lot of time to commit slow resources to meet the peak demand. Now, when you start looking at this and you look at that blue bar it really tells you now, 50 percent or more of your demand, you need to get that in three minutes.

And when you start looking at this a little closer, which is the orange bars, it tells you on some days over 70, like on March 4, at the one-hour we had to ramp 7500 megawatts. And that's a lot of ramp.

When you -- to put this in perspective, 7500 megawatts is more than one and a half times SMUD's peak load. So trying to move that amount of energy in a short period of time, it's a lot. And then you got to do this judiciously.

It's not -- when you try balancing supply and demand, some folks think, well, if let's say you're looking at five minutes or 10 minutes, if everything is balanced then you're fine. Well, I have a couple plats to show you it's not.

Now, when you're looking on the good side, when you look at the percentage of load met by wind and solar on some days, even though on September

1st, 2017, was a peak day, we have 24 percent of the energy supplied for just about a minute from just wind and solar.

Then when you look at geothermal, biomass, biogas, all the RPS resources it was about 30 percent. And then when you look at the last hydro and the nuclear plants it was about 44 percent. What really struck us was last -- two weeks ago on May 26th we saw a 64 percent after load served by wind and solar.

And then 93 three percent from noncarbon resources, and that's pretty impressive, you know, when you look at these numbers. Then looking at this across a whole day is another way to look at it, and I'm not going to go into all, but on May 26th 34 percent of the energy for the whole day was served by just wind and solar.

Forty-four percent was served by renewables and almost 66 percent from noncarbon emitted resources. So again, these are pretty high normals, and it's pretty impressive, being able to control the grid with so much renewables.

In terms of carbon remission over the past four years, we saw a reduction of about 24 percent. So far this year, 2018, we had one Diablo unit out back in March time frame. Also, we had more hydro back in 2017, so -- which shows you that upward tic in the red curve.

So we expect that to drop as, again, with Diablo and more and more renewables on the system. Moving along, some of the observations we had looking at some of these days, we have been seeing, you know, renewables serving more and more load. Renewables gas decreasing and it's down to about 24 percent.

Minimum net load continues to drop. Also, curtailments is continuing to increase. And so we're taking a close look at trying to see how we could minimize curtailment. Ramps are increasing and it's expected to get, you know, larger.

During the spring months it depends on the net load. If net load's low we rely a lot on the inter ties to bring or to meet some of that ramp, and if net load's high we could rely on some of the internal resources to help you meet that demand.

Now, this plat here is pretty impressive. I'll spend, you know, a little time trying to explain what it means. Now, unlike other places, you know, like Europe where they operate, they do not have the control performance standards we have to comply with in the U.S.

We have strict standards that the operators need to abide by. We have to meet. Also, you know, it comes with noncompliance for some of these matrices comes with hefty fines. So on this plat what we really wanted to show here is that green line is 100 percent.

So when, as the balancing of our day in the west, we got 38. So we have an obligation to supporting the connection frequency, as I said, every minute. So every minute we do a calculation to see, did we really help support inter connection or did we lean on the inter connection.

So if for one day you see on this day, on January 31st, we had 11 hours where it was red and the remaining hours was blue. Now, whenever you see blue that means we supported the inter connection frequency.

When it's read it shows we have a tendency to lean on the rest of the inter connection. Now, that red curve is really net load, which again, is load management minus hour. So when we started looking at this, I remember back in -- the 31st, this was a weekend and not Monday, I was telling one of my co-workers, you know, I said, we have a lot of challenges on controlling the grid over the weekend.

And he asked me two things. He said, one, did we drop load, and I said no. Secondly he said, did we go into a stage emergency. I said no and then he says, well, what's wrong. Well, a lot of folks does not realize system operators have, as I said, an obligation to control the system.

Now, on one day we could 11 hours where let's say we lean on the inter connection. Tomorrow, we can have eight hours where it's, you know, pretty hard. Nope, does not say you need to meet the standard 24 hours, 24/7. Right.

Well, so some days you may have a bad day, but what we started doing on the ISO is we took a proactive approach where we started looking at this matrix on an hourly basis. Now, for compliance, if you look at this at the end of the day your score would be over 100 percent most of the times.

If you look at this across a month it would be over 100 percent. But currently, when you look at it, this is what we're reporting out, is how well we did over the past 12 months, rolling average. Our score right now is about 120 percent, which is really good.

But by us looking at this matrix on an

hourly basis we can tell where we can potentially see problems. So now, on this day for 11 hours we have problems. When you solved overlying things like wind and solar, like on this says, over -- everything above that green line is good. Below that green line is bad and our target performance should be that green line.

Now, when you look at wind and solar on that day you can see a pattern, right. When this is -- it was windy. It was gusty. So when you have variability of wind, which is green, and you see you lost 1700 megawatts in less than half an hour, then you kicked up 2200 megawatts again in half an hour, you can see how difficult it is to control the grid.

Now, in order for everything to work right you got to be able to forecast this dead-on accurate, and remember, too, in the old days when we controlled the grid you had controllable supply and you had predictability math.

Today, in California the load is no longer predictable because you got things like plug-in electric vehicles demand response, you know, energy efficiency. So it's making it a little more challenging, even combining heat and power, right, causes some challenge in forecasting what that load's going to be.

It's no longer temperature dependent as it used to be. And then, of course, you know, electric vehicles and then the big gorilla in the room now is rooftop PV. So while we control the grid today, on some weekends we have 25 percent after supply we don't see, which is rooftop PV.

And trying to maintain a balance between supply and demand, and we do this as I said every four seconds, it's -- is becoming a challenge right now. So again, this is what we see on some days, you know. And then stepping back, you may have a good wind forecaster, you may have a good solar forecaster, you may have a good load forecaster and a good rooftop PV forecaster, but when you put all four together a day ahead, try to predict what it's going to look like 24 hours from now, it's pretty difficult.

Some days you can get it right. Some days, you know, the errors can add up. When it adds up you have a control performance issue. So looking at this plat, you can see for the first four months of this year, looking at every day, where we tend to see problems.

And you can see something that's pretty

distinct. During sunrise and during sunset we tend to see challenges controlling the grid, right. As I said, this is not a problem today. It's a potential problem.

NERC started to look at this pretty close. As a matter of fact, NERC started -- and you have a severe out where they want all balancing authorities in North America to do a study on their system to see, as more and more renewables come on, do they have or do they anticipate ramping problems.

Now, three -- about three and a half years ago when we started at NERC saying hey -- we started to see some unique problems with solar, especially during sunset, but nobody understood what that meant, because nobody else had the amount of solar that we had out west.

And then NERC created this Essential Reliability Task Force to look at what would it take to degrade more and more renewables onto the grid. And everybody knows the first two, right. One is frequency control. Second is voltage control.

And then out west we said, you know, we started to see a ramp run up. We have a ramping issue. If you go back and look at the report that was published by NERC in 2013, the whole section on the ramping issue was done by the California ISO, because we were the only entity starting to see a ramp issue in the country.

Well, ironically, last year we had Duke Energy, NorCal Energy, they came out. They wanted to say, we want to see all these studies you guys did, because now they have 13 megawatts of wind -- I'm sorry -- solar, and they have a ramp issue. They have some concerns.

So it started out west, starting propagating back east, and by first looking at the system on this granular level, now we know where we have problems. Now, we can look for potential solutions to address this.

So when it comes to control performance, this is something that, you know, I know a lot of folks here, well, they do this in Europe. They have a lot more wind. They have a lot more solar on the system, but again, they do not have the control performance standards that we do.

Under the U.S. we got four standards that we have to comply with in real time. And again, if you fail one of these it comes with hefty fines. This one here is looking at the ability to control the system frequency on a minute-by-minute.

There's another one that we have 15 minutes. Anything goes wrong in the system we got 15 minutes to get the system to where it was just prior to that event. Fifteen minutes and four seconds is late and you get hefty fines.

In addition to the hefty fines that you get by NERC and FERC. The west, they make you carry three months' excess reserve, and that's costly. And again, there's another standard why now in the old days we could dispatch contingency reserve to meet a contingency if something happens in the west.

A year and a ago FERC had this new standard where now, anything happens from Colorado all the way out west, any unit greater than 500 megawatt that's lost, we have an obligation; we have 52 seconds to meet that obligation.

So when we operate a lot of folk things that, well, it's just a matter of balance in supply and demand. Well, balance in supply and demand on a four-second basis, as I said, we do two things. One, we balance the system every five minutes, through a market, which makes sure that that anticipated load for the next five minutes, we meet that with the cheapest energy in state and out of state.

But then within that five minutes we balance the system every four seconds, because what is it we're trying to do is supply and demand. And if, let's say in five minutes -- this is just one concept that's pretty interesting.

Let's say you need 100 megawatts in five minutes and you five me 100 megawatts in the first minute and nothing in the next four minutes, it shows up as very bad controls when you start looking at your control performance for that five-minute interval.

If you give me everything the last five minutes and nothing for the first four minutes, it's bad controls. But when you look at supply and demand, everything may balance at the end of five minutes, but as a control performance engineer, this is what I see and this is what we have to address.

So when it comes to balances, balance in the system, it's every four seconds. And then every four seconds may seem fast to some of you, and some of you may -- you know -- heard me in the past say this, but when you think about -- and a nice way to explain this is, you're driving on the freeway at 60 minutes an hour with your eyes closed, every four seconds you open your eyes to see where you're going.

Well, in the old days that was easy because the road was pretty straight. Now, with the amount of renewables it's pretty windy and it's very, very difficult to do that, you know, balancing the system, because what it is, electricity travels at the speed of light and trying to do this every four seconds is pretty slow.

So we're looking at ways to address these. So a lot of the things that goes on behind the scenes, we are looking at a lot of solutions to integrate more and more renewables, minimize curtailments.

Some of the opportunities, this is one here that shows the oversupply and this is something, you know, we want to minimize, curtailment. And you can see, so far in 2018 we're right about 2.3 percent of the potential production from solar.

It's not too bad. Even though it looks high on this plat, 2.3 percent is still low looking at overall potential production. Again, this is here, it shows you the negative prices from 2012 through 2018.

Back, you know, six, seven, 10 years ago, it used to show up at 4:00 a.m. when we had oversupply. Now, when you look at this, oversupply really shows up from about 9:00 a.m. through about 5:00 o'clock in the evening.

So last year was pretty bad. We had a lot of hydro. And again, this year the blue bars to the extreme right of each hour is not as bad as it was last year, but still, you can see the potential for oversupply.

EIM is helping, because on some of those days, you know, especially the day we had minimum load, February 18th, we shipped out 2,000 megawatts to EIM participants, but yet, we had to curtail about -- oh, no. We did curtail about 2,000 megawatts, but we were able to ship over 2300 megawatts to EIM participants, which really helped in terms of curtailment.

Again, here we have a lot of folks looking at ways to enhance your control performance, looking at things like storage, looking at fast-moving devices. We're also looking at ways that we can control the system, you know, a lot better than this four seconds.

We're working with NERC to see how we could get some of these standards, I wouldn't say relax a bit, but done in such a way where -- well, let me step back. These standards are really developed for conventional resources.

Now, when you want renewables on the system we got to rethink some of these standards. So we started working with NERC to see how we can get some of these standards changed. One of the things we did in terms of forecasting, we had a time lag, and when the forecast came in to when it went into the market runs, but about a month and a half ago we cut that back to about six minutes.

So now, we started to see an improvement. And especially on our windy days when the forecast tends to lag actual production, you have problems. Here, by able to cut six minutes off the forecast to when it gets into the market, it's helping.

But also, we are working with universities. We're trying to get better forecasts and we are working with the Northwest Labs, trying to get a probabilistic forecast fed into some of the decisions that we make to help.

One of the things we're doing right now, we're working with Southern Cal and we're working with a solar developer. We want to get a solar plant participate in regulation service, and that's going to happen soon.

We're also, next month, we're going to test a wind plant for some of these services, the essential reliability services like regulation, voltage control, frequency control, inertia, frequency response.

Some of these solutions, I'm not going to get into this, but we have about eight initiatives right now at the ISO. Each one of these, you know, you could spend at least a day going into. Term of use rates is pretty interesting and minimum gen.

EIM, regional coordination, you know, they're all going to help. EIM participants, we're looking at SMUD, LADWP coming in pretty soon, and then we're also working with CENACE, Baja, California, to get -- see how soon they can join EIM.

Again, trying to minimize the curtailment. You can see from about January 2015, cumulatively we avoided a lot of curtailments. Again, this is partly due to being able to ship some of the renewables out of state and being able to -- well, a lot of other things happening, you know.

How can you -- one, I think there was one slide, somehow it didn't get in there, but another opportunity here was getting renewables to provide essential reliability services. We know they can do it today. We're going to prove that with this wind plant next month.

Once they can do it, you know, we think we need to relook at, you know, some things on the system. So if a renewable plant can provide the essential reliability services, then utilized that as opposed to committing a carbon emitting resource to provide the same service.

So with that, I think this is the end of my slide deck, and are we going to get everything processed now or --

CHAIR WEISENMILLER: Thank you. Just a few questions. First, I was going to observe, as you compare your -- one of the thing they do, they do have an integrated continent-wide market. Obviously, Germany has four balancing authorities, but there's a lot of flexibility in terms of they have the coal-based falling on one side, nuclear placed France on the other, and obviously, Norway above.

But you know, that's one of the advantages of a regional market, you know. Certainly, Europe shows as much easier to do. I don't think Germany could have survived, you know, the grid if they had just, you know, just limited it to Germany, per se.

I think the observation I was going to make is we look a lot at the duck curve. In Texas Court it's called the dead armadillo curve, and from their wind focus. But ERCOT has really always put in much stricter performance on wind, and now with their having increased amounts of solar, that they really have to have capabilities more like any other power plant.

And I think that's one of the reasons that they've been able to deal with what's a huge amount of wind compared to California. And also, but I mean, they're certainly dealing with similar operational challenges as we are.

I think I was a little surprised you didn't have the eclipse day. I mean, that was certainly a good new story of how we got through that.

MR. LOUTAN: Yeah. We did pretty well on that day. So it wasn't really operationally a challenge. We got a lot of help from the solar plant. But back to Europe and Germany, you know, when they have oversupply they have no rules right now to contain that oversupply within Germany.

CHAIR WEISENMILLER: Right.

MR. LOUTAN: So that allowed that energy to flow, you know, on the system. So we had the Germans here about a year, a little over a year ago. And one of the things I asked was, you know, how do you deal with oversupply? They go, well, we just allow it to flow.

CHAIR WEISENMILLER: Yeah.

MR. LOUTAN: Then ironically, about three months after, I saw an article where Czechoslovakia had said, well, we can open supplies up. We just can't deal with this --

CHAIR WEISENMILLER: Right.

MR. LOUTAN: -- open supply because it causes losses. So but in the U.S. if we have oversupply we've got to contain that within the ISO. We just cannot ship that out to our neighbor in VA, because of the strict standards that we have and we must comply with.

So that's what makes it a little more of a challenge, you know, for us than -- and then they do not have this standard where they have to support inter connection frequency as we do. So we have some differences in there.

I look at ERCOT quite a bit, also, to see what it is, you know, they're doing. They get a lot of frequency to move quite a bit, but they start dropping load when the frequency drops, you know, below what we see in the west.

So in the west if we have low frequency of 59.5 we start tripping load, and ERCOT is, you know, way below our 59.5. So they have a lot more leeway, but they also have about 1400 megawatts of load that they'd trip in half a second if something goes wrong.

It's something that we started to think about, you know, how can we copy some of what they do, you know, in ERCOT. Some of the things, you know, we're looking at is, is implementing ramp rates on renewables.

One of things, you know, I like from ERCOT is that 10 megawatts would be max a day. So we are looking at other entities, what it is they're doing, and so we're not trying to reinvent the wheel, but apply what it is other folks' doing.

And Mike *17:50:42 is coming in from Germany next month. So I'm going to have him for about two months to see everything that they do across there.

CHAIR WEISENMILLER: That's good. I think we certainly need to keep looking at lessons learned, I mean, obviously, because ERCOT's like

20,000 megawatts of wind.

MR. LOUTAN: Yes.

CHAIR WEISENMILLER: I think they're probably more like 1,000 or two of solar.

MR. LOUTAN: Yeah.

CHAIR WEISENMILLER: But coming up pretty quickly.

MR. LOUTAN: And they're really wind, you know, their geographic diversity helps you minimize variability. So when we started looking at ramps, ERCOT, they went from 14,000. So they did a study from 14,000 to 21,000 a day. So no ramp issues.

Whereas, you know, we got solar, and when the solar drops off you don't get any kind of geographic diversity. You lose it. So you got to make the ramp up. So this is what makes the west a lot different from everybody else.

And then nobody else has the amount of rooftop PV that we do. So we got -- we kind of like have a double whammy trying to maintain performance, trying to deal with these ramps. And then they belly of that duck is really a challenge for us, also.

CHAIR WEISENMILLER: Yeah. And certainly, if you look at our PV forecast you could get to zero, you know.

MR. LOUTAN: Yes.

CHAIR WEISENMILLER: In sort of a discrete period of time. I guess the -- one question I had is last year you talked about the solar project where you did the experiment with the inverter, and you know, it was really pretty impressive.

And obviously, one of the things I'm trying to understand now is what are we doing to move that from, you know, a one-off experiment to standard practice throughout every solar facility in California?

MR. LOUTAN: Now, I know my boss is involved with a team right now, you know, and I know they're working with -- you know -- if Delphine is here, she might be, you know, more, you know, into this than I am.

I'm looking at just one plant participating in regulation service. But Delphine, and later on she may talk about this, she's more involved in working out a program where we can get renewables to participate in or provide in essential reliability services.

CHAIR WEISENMILLER: All right. I think it's important. You know, I think we've lost eight within a year, you know, 800 megawatts of gas plants. So the question is, how do we move other resources into that flexible category at about the same rate.

You know, obviously, the gas plants can go away much faster than we can get the converters out or demand response with some of the other things we're trying to do. So what it hoping to do today was really in still some urgency in the agencies to make concerted action on the other flexible resources.

MR. LOUTAN: Now, one last thing here. One of the takeaways, you know, from my slides, when you saw looking at the three-hour ramps and the one-hour ramps, it really shows you the need for speed on the system right now.

It shows you -- and I hope the message where if I have 10 minutes or five minutes to balance a system and I do everything in the first minute or the last minute is not good. So this is where we need to rethink and this is where, you know, faster units comes in, storage comes in, other type of devices to help you control the grid.

COMMISSIONER HOCHSCHILD: Could I ask you a question. We're -- two weeks ago we passed the

400,000 mark for electric vehicles on the roads in California. We're adding about 12,000 EVs a month now in the state.

I'm just curious your thoughts on the role of EV charging as it pertains to grid reliability, what trends you're seeing so far and what role you think that could play.

MR. LOUTAN: I think -- well, two things. One, with the term use rates I think it's going to help if we use this EV right, it can help you, you know, raise the belly of the duck. It'll help you do some load shifting.

But what I would really like to see EV comes into play is in terms of frequency control. So the concept is, you know, you come home, you plug your electric vehicle in. You think, well, it's going to take me 50 percent charge to go to work tomorrow.

So you just dial 50 percent. Everything beyond 50 percent you could use that as frequency control on the grid. So and it's going to be transparent if we do this right. When I say transparent, in the sense that you go home every evening. You plug your electric vehicle in.

At the end of the month you get a check

from PG&E or Southern Cal that says, look, $50 you helped me do frequency control. So it has to be transparent to the user and it has to be simple, and we need to figure out how to do it.

So these are some of the things, you know, we're looking at, at the ISO. My boss and I, you know, we sit and we talk about some of this stuff and we think there are ways to do it. So we're still in the infancy stages, but ultimately, I'd like to see electric vehicles be used to control frequency.

CHAIR WEISENMILLER: Yeah. Thanks.

MR. LOUTAN: Um-hum.

MS. RAITT: Thank you, Clyde.

Next is Neil Millar, from the California ISO.

MR. MILLAR: Thank you and good morning. I'm going to give a fairly brief overview -- I'm going to give a very brief overview today of the ISO Summer Assessment prepared really to help our operators understand the conditions they reasonably can expect to be looking at this summer.

And just in contrast -- I'll actually start with the last bullet on this slide first. In contrast to many of our longer-term planning studies, this really is an operational study that at times throws in a bit more pragmatism than science to really try to give the operators a better assessment of the conditions they'd be looking at.

It is a probabilistic approach, looking over -- and we take 2,000 scenarios out of a possible 8,000 that have been developed, a sample of 2,000 scenarios and do production simulation analysis of the entire summer period, the 2928, just almost 3,000 hours in the summer period, to look at a wide range of load forecasts and other operating conditions that could come their way.

It does focus on resources that qualify as resource adequacy resources. So we model that qualifying capacity as opposed to the P-max values, perhaps of different generators. And we do take into account known outage rates, as well.

Now, the -- jumping to the end first, we are expecting a fairly tight 2018 summer result, based on our assessment. We are projecting a 50 percent probability of a stage two emergency happening at least once through the summer, and I'll talk a bit more about how we've landed on that.

The primary issue, even though the load has not changed materially from 2017, the system load we see has not changed, the primary issue is that the hydro conditions we're anticipating are far more serious than last year, where last year was above average and this year we're going well below average.

As well, there have been gas generation retirements that Chairman Weisenmiller already referred to. We have not tried to take into account any specific gas restrictions associated with Aliso Canyon.

At this time we see that more of a localized issue, as opposed to necessarily a system. And this analysis is focusing on system capability through the summer. As I mentioned, the hydro conditions we're looking at are significantly below 2017 levels.

This graph provides the north, central and south hydro conditions, or snow pack conditions, that we were looking at through the winter. And the light blue shaded area are the average conditions. The purple line at the top is the highest we've experienced.

The orange line is the 2012-2013 condition, and that's the hydro scenario that we've used in our summer assessment, to take into account the available energy for dispatch, as well as the run of the river profiles, basically because it's a very close match to the hydro conditions we expect that we saw around April 19th.

So with those values this gave us a reasonable projection to use, or how that and the hydro energy would play out over the course of the summer. And I'll circle back on the impact of the hydro market just a bit later in the deck here.

Now, the metric that we have been focusing on is what we've called the minimum unloaded capacity margin. And what that margin is, is the amount of available hedge room left on generation that is online, as well as the available capacity from generation that could be started in 20 minutes.

It's a bit of a pragmatic metric that the operators can turn to, to give them a feel for what they have available, especially to deal with unexpected circumstances, and how that leaves them situated relative to our operating reserve requirements.

Now, I mentioned that we've studied 2,000 scenarios out of a possible -- out of all the possible 8,000 that we had constructed. What we take from each scenario is the lowest value that was observed through the summer from that scenario.

We take those 2,000 scenarios and then place them and check them against operating reserve requirements. And what this graph demonstrates is that 50 percent of those scenarios still maintain a six percent reserve or higher.

Whereas, approximately half of the scenarios after fell below the six percent line. So the column labeled 968, that's almost all exclusively in the below six percent. Now, you'll notice that the distribution drops off quite sharply.

So while there's -- we're projecting a 50 percent chance of entering a stage two emergency range, the chance of a stage three drops off very significantly with relatively few scenarios, but there are scenarios that have us below three percent and into the stage three emergency alert area, as well.

Now, in terms of when those occurs, and I think this ties back not only to the ramp rate issues that Clyde talked about, but also, what is the level that you're ramping to as the solar drops off. We've observed that the vast majority of the low hours of operating reserve availability, the vast majority of those hours occur in the post-solar window.

So it's really an issue of we have sufficient capacity to get through the system peak load while your green-connected solar is still available, but the impact of a load dropping a little, but the solar dropping a lot is leaving us in a more -- in a tougher situation between 4:30 and 7:30, in that post-solar window.

The other observation was that nearly all of the operating reserve margin worst case scenarios were in September, the scenarios below three percent. So that also aligns with the expectation by then that we've pretty much exhausted the hydro supply down to its minimums, and that's when the operating reserve, coupled with higher load since September, which we've been seeing more frequently, September becomes the more critical month for getting through the summer.

Now, in terms of preparation, as in the past, in past years, this analysis has been shared with a number of state agencies, government offices, and it's also used, of course, in the ISO coordination with other state agencies, utilities, and so forth, to be as prepared as we can for summer, so that people have as much visibility in advance of the kind of situation we're looking at.

So like I said at the beginning, we are seeing a significant chance of getting stage two, but very slight chances of beyond that, reaching stage three. I'll stop there and see if there are any questions I can help with on this.

CHAIR WEISENMILLER: Yeah. I just want to circle back on Aliso for a second, you know, that obviously, we have the problem of the pipelines being out, and your typical solution for Aliso problems is to shift generation out of the basin.

So the question is, how does that need to shift generation out of the basin interact with the overall assessment you have here, i.e., should we be more nervous in Southern California than looking at the statewide levels?

MR. MILLAR: Well, some of the operating challenges that are unique to the local area will be an additional concern. But in terms of the total supply impact, one of the things we're dealing with, and it's not lost on us that we're showing a fairly serious situation, even before the rest of the OTC generation retires, which would result in a much larger drop in total available gas supply.

But part of the situation is which gas fired generation is going away. Right now, we do see that we can accommodate the loss of more slow ramping, slow start generation without having a material impact on these results.

Now, there are other implications, but on these results they wouldn't change significantly due to the loss of some amount of slow generation and the OTC generation is relatively slow start and slow ramping.

So when we look at that we don't see the Aliso situation necessarily affecting the total system capability, but we don't think we're out of the woods in understanding all of the interactions yet, either, that we -- of the gas system, number of gas pipeline outages that are currently on the system, and that's something that will need more work and future evaluations.

We do think this gives us a reasonable projection for our operators for this year, but some of this work will both need further refinement and more consideration in the longer-term planning. So we are taking this work and also looking at what does that tell us about how we should perhaps be looking at any of our long-term planning studies differently, as well.

And with Aliso Canyon, one of -- if there's adequate pipeline capacity one other solution is with Aliso providing historically more of the shock absorber affect to handle unexpected increases in demand.

An alternate solution was also to increase the dispatch of generation ahead of time, have more gas flow scheduled in the pipelines. But with the gas pipeline outages we're looking at that also becomes more of a challenge.

So this is certainly an area that needs more work. We're going to be doing a lot to try to support the CPUC process looking at Aliso Canyon, as well as seeing what we can take from this into our Transmission Planning Studies.

COMMISSIONER HOCHSCHILD: This is more just a point, particularly maybe for Brian Early and any others in the room who are engaged with some Title 24 on behalf of the Energy Commission. The -- you mentioned the solar generation, and for fixed tilt systems and still in California, they're almost entirely south facing.

When you do west facing systems what happens is you generate about 20 percent less kilowatt hours over the course of the year. So the valid proposition for the customer is somewhat less. But you generated 55 percent more generation between the hours of 2:00 and 8:00 p.m.

I really think as a state goal we have got to be pushing hard, particularly now that we're doing solar as a mandate for new construction, to insure new systems going in are done west facing or as many as we can, and it's -- you know -- I think the time use rates will help to some degree, but I think particularly with new construction where the builders who are building the systems are not the people who are going to be paying the electric bills, it's a tough nut to crack, but we got to be thinking about that, I mean, as a goal to be promoting west facing PV, because I think it will really help with the issues you're raising.

MR. MILLAR: Just to reiterate the point Clyde made, well, Clyde's material is focusing primarily on ramping, and I think our work focuses here on both, both the ramping and what you're ramping to, level of capacity at that time.

At this point we're seeing that there's room for all of the solutions, and at the present the situation is actually continuing to worsen.

They haven't bottomed out and started to improve yet. So we certainly need the focus, let's say on all of the possible solutions, too, all through this. Thank you.

MS. RAITT: All right. So thank you.

Next is Michele Kito and Jaime Gannon wasn't able to join us today, but Michele Kito from the California Public Utilities Commission is here.

MS. KITO: So today I'm just going to be talking about the CPUC's Resource Adequacy Proceeding and some of the issues that we're seeing in there, and the Proposed Decision, which is on the Commission calendar for tomorrow.

I'll just be talking a little bit about the background and history, structural changes and emerging issues that we've seen, including one-through cooling retirements and replacements, growth in community choice aggregators, less forward contracting, local waiver deficiencies and backstop procurement, both RMRs and CPMs, so reliability must run contracts and the use of the capacity procurement mechanisms.

Then finally, we'll talk about the Resource Adequacy Proceeding, the Proposed Decision and the Track 2 Schedule. So just a little bit of history.

Several years ago we had the Joint Reliability Proceeding.

It was open to consider policy proposals to address the existing reliability framework for electric procurement. That was to insure that we had the resources needed for the grid. That was closed early, in part because we were going to wait for the development of a permanent, flexible product, and once that was considered we thought that we would reopen the issue.

The issue there is we didn't want to put resources under a multi-year contract, since we didn't know which resources we wanted. We wanted to make sure that we had the right resources. That decision ordered the Energy Division to collect information, which we've been doing and releasing reports every year -- almost every year.

So the issues from the Joint Reliability Proceeding were move to the RA proceeding.

CHAIR WEISENMILLER: Can you make your slides *18:10:14?

MS. KITO: Oh, sorry. Sure. Okay. Thanks. So last year the Decision addressed this issue of a multi-year framework and said, again, that we wouldn't -- that the precursor or what was required was durable, flexible products.

So it declined to adopt a multi-year proposal, but it left open the possibility that it could -- that the Commission could address it. This year in the Scoping Memo the Commission did indicate that it was willing to consider multi-year RA, even in the absence of the adoption and definition of a durable, flexible product.

So now, I'm just going to turn to some of the structural issue changes and emerging issues that we've seen over the past year. As CAISO has talked about, we are integrating greater numbers of intermittent, renewable resources, and they talked a lot about that.

They also mentioned and we'll talk a little bit more about retiring or repowering of significant amounts of resources that utilize once-through cooling technology. We'll also talk about the rapid expansion of community choice aggregators, and then we'll talk about waivers and CAISO procurement.

So this is kind of busy, but it basically tells you the recent and expected retirements of OTC units. You can see that that's about 7,000 megawatts. Some of these have -- or these are the upcoming retirements, or announced retirements.

So just this year, Ormond Beach, which is about 1500 megawatts, and Mandalay 1 and 2, 430 megawatts, announced their retirement. The bottom are the resources that were considered in the very old LTPP at this point for a placement for those retirements.

So you can see that we have Carlsbad in the San Diego area, and Pio Pico to a lesser extent, and in L.A. Basin we have Alamitos in Huntington Beach and the Wellhead Plant. And those are expected to come online in 2020.

So moving to the next page, I'm going to talk a little bit about local areas and CPUC jurisdictional LSEs. So this is just a map of CAISO's jurisdiction, and then we would just want to mention that CPUC jurisdictional LSEs account for about 90 percent of the load in the CAISO.

There are currently 39 LSEs. We have three investor-owned utilities, 20 community choice aggregators and 16 electric service providers. Okay. So this is a graphical representation of the issue we're seeing with regard to the growth of the CCAs.

So if you look at the far left chart, those were the load share ratios in 2017. So you can see that the IOUs were serving 88.4 percent of the load, ESPs about 8.5 percent and the CCAs, 3.1 percent. The middle chart was our year ahead forecast.

So that's the forecast that we had last year and that's what we used to allocate requirements -- RA requirements. That's the middle chart. Again, you can see the percentages and you can see that CCAs were expected to be 6.2 percent, based on the forecast last year for this August.

Now, we'll go to the far right chart, and that is based on the August revised forecast. This is now what we expect to see this August, and you could see that the number of CCAs has grown considerably.

So in all these cases it's almost doubled. so it's doubled from 2017 to what we expected for 2018, and it's doubled from what we expected to what we're seeing -- nearly -- in 2018. So there's a considerable amount of CCA load growth uncertainty, and we just want to highlight this and it makes planning somewhat difficult.

You can see in this, if we looked at the implementation plans that are filed at the PUC, 4/20/18 we would have expected to see CCAs at about 15 percent. And remember, if you go to the last chart, what we were expected as of the August load forecast was 6.2 percent.

And if you look at Implementation Plans that are filed with the Commission for August of this year, it would have been 15 percent. Again, if you looked just a month later on January 1st of 2018, that would have been 19 percent, based on the implementation plans, but not everyone chose to move forward with their expansion -- CCA Expansion Plan. So we are now at the 10.9 percent.

So this highlights two things. It makes planning a little bit difficult, and secondly, there's a large amount of intra-year uncertainty at this point. So those are the purpose of those. Just going to talk a little bit about Forward Procurement.

So when we did the JRP in 2014 we looked at how much procurement was happening in the forward space, and at that point in time we thought we saw some significant forward procurement. So what we saw in 2014 was that for the next year there was 95 percent of the procurement was completed, and for the following year, August of 2016, 85 percent.

So that would indicate that most of the system requirements, at the very least, were met on a forward basis. So now, we look at the most recent contracting analysis report that is based on an April 2017 snapshot.

And it indicates that for the next year at that point in time, 75 percent was procured for 2018. And if you remember the way the procurement goes, usually, the requirements come out in July. So everyone will be roughly 100 percent -- well, I think 90 percent procured in the year ahead time frame for system.

But a lot of the procurement happens in the summer and this snapshot was April. So that's why you're seeing 75 percent. In any case, for August of 2019, based on that snapshot, it looked like it was 69 percent.

And this also includes the effect of ELCC. So we adopted an ELCC. So you might have had resources in your portfolio that were solar and you could account for a certain amount of that NQC, but with the decision which reduced the NQC, you would -- it would look like you have less in your portfolio. So that explains some of the drop.

So staff concluded that there had been a decrease in the forward procurement activities since 2014, when we were looking at the JRP at that time.

Okay. This is kind of a busy chart, but it just tells you who is doing the procurement.

So we have different kinds of procurement. We have IOU procurement. We have CCAs. We have ESPs, and we also have central procurement, which is done through CAM. So in the last decade or so the Commission has authorized the utilities to invest in new resources, and those resources are primarily for reliability, and those resources are -- the costs are allocated and the benefits are allocated to all customers.

And that shows you -- that's the CAM line right there, down there. So this is as a percentage of the local requirements. And so if you look at this you would say, well, we're over-procured in 2017 for the local requirements, but the issue is, local resources are also used to meet system obligations. That's why you'd be over-procured.

So a couple of important points for 2017. The procurement percentages roughly match what you would expect for the load that they had, if you ent back to the chart we had before. Those drop off fairly significantly in the outer years.

We are now collecting additional data and we will update this, and there -- we believe that there has been more forward procurement, some additional forward procurement. Going to talk quickly about the local capacity areas.

The CAISO performs LCR studies every year. Those are based on one in 10 weather years, and based an N minus one, minus one contingency. So they're basically looking at what resources you need in the local area if you have a very high load day and if two transmission lines go out, the important thing is we have 10 local areas, but we have 45 sublocal areas.

So CAISO not only looks at the local areas, but it looks at what resources we need in smaller areas, well. CPUC, from our perspective we aggregate six of the local areas to address market power concerns, and those Sierra, Fresno, Humboldt, North Coast, Stockton and Kern, and we would aggregate into PG&E, other areas.

So we allocate the requirements to give areas, Bay Area, other PG&E, L.A. Basin, Big Creek and San Diego. Annual compliance is due on October 31st. CAISO does an analysis to see if they get the right resources, both in the local areas and the sublocal areas.

So this chart, again, is also busy, and it really illustrates two points. One is the number of subareas in each local area, which is to say, not only do you need to get the procurement in the right local area, but you also are aiming for trying to get the right procurement in very small areas, as well.

The other issue that this illustrates is how many resources in the area you need. So you can see that in Stockton we pretty much need every resources, and Sierra, as well. And it also will give you some indication potentially of the market power that generators in any local or sublocal area might have.

Let's see, local reliability concerns. The CPUC has a local waiver process to mitigate market power and that was because there's high concentrations in certain areas and not some areas. The trigger price is $40 a KW year.

Prior to the 2018 year LSEs has only ever filed two requests for local waivers. In 2018, of the 27 LSEs we had at the time, 11 filed waiver requests in aggregate, requesting waivers for 270 megawatts of local deficiencies in the San Diego area.

We've also had over the past year the

emergency of backstop procurement. We had considerable amounts of backstop procurement. I have categorized it into CPM and RMR. On the left hand is the capacity procurement mechanisms that were picked up.

It was Moss Landing 2 for 510 megawatts, and the prices are shown there, and Encina 4 and 5. With regard to RMR -- oh, and I will just say, the CPM is determined after the -- okay. I'll go faster. So the RMR procurement included Metcalf, Yuba City, Feather River. You can see those.

You can see that these are considerably more expensive than the RA procurement we've seen in these areas to date. The track 1 decision proposes a multi-year resource adequacy requirement starting in 2020 and a central buyer, and it also addresses issues regarding load migration from utilities to CCAs.

The Proposed Decision concludes that a three to five-year local requirement should be initiated for 2020, that 100 percent local requirement is appropriate for the first two years, and for years three and beyond, if adopted, parties are directed to propose percentages that were consistent with what we found in the past.

I won't go into this, but we did -- the Decision does talk about a central buyer or -- and gives a strong preference to a single, central buyer per track area. The -- just wanted to mention that Ormond Beach and Ellwood generators have announced their retirements, and CAISO determined in their local study that they're needed for local reliability.

The PD authorized Southern California Edison to contract with these generators, if possible, and allocate these costs to all customers. Similarly, it noted that if other issues arose that the utilities are authorized, but not required, to contract with these resources, to the extent that they can try to procure them at less than backstop prices.

the schedule for track 2, which we'll be considering, that local program, is right here. Testimony's due on July 10th. Workshop's in July -- responsive testimony in August, hopefully with a PD at the end of 2018. I'm happy to answer any questions.

CHAIR WEISENMILLER: Yeah, I have a couple. Could you explain the CAM to me, where you had the one chart of who was doing what procurement there's the CAM, unless I ran into -- I've not ran into that before.

MS. KITO: Sure. CAM stands for cost allocation mechanism.

CHAIR WEISENMILLER: Right.

MS. KITO: And in the 2000s the Commission determined that additional resources were needed for reliability, and they weren't certain that anyone was willing to do it. So ESPs might not be willing to do it, because they only have customers for a short period of time.

At that point in time I don't believe there were CCAs and the utilities were concerned --

CHAIR WEISENMILLER: Okay.

MS. KITO: -- about load migration and were unwilling to undertake that procurement without some assurance that everyone paid. So the Commission authorized some procurement and allowed them to spread the cost to all customers. So for example, the Alamitas and Huntington Beach --

CHAIR WEISENMILLER: Okay.

MS. KITO: -- are spread to all customers in Edison's TAC area.

CHAIR WEISENMILLER: Okay. And I'm not surprised the IOU numbers are going down. I think it was last year the utilities were clear they were not doing the under five-year procurement, because of the uncertainty on CCAs. You know, they just stopped.

So I would anticipate over time you'll see less and less utilities as they try to work down to what they the levels to be on longer term.

MS. KITO: Right. And that's why the decision both authorizes or intends to authorize multi-year procurement, so that you could get those levels up to where we saw them in the past, and also proposes centralized procurement to address the load migration issue and load uncertainty.

CHAIR WEISENMILLER: Well, what are the CCA incentives? You had pointed out all the uncertainty. Obviously, the very large implementation plans, but much smaller elements here for the forward procurement.

So what happens if they basically have a certain level they contract, but then they exceed that level, you know, and don't have contracted RA for those additional resources? Is that just CAM or just how does it work?

MS. KITO: Oh, there -- the Commission has a penalty mechanism. So if somebody doesn't come in with the resources that they're -- that we've allocated to them for TA purposes, either in the year ahead or the month ahead time frame, we have a penalty provision, and the penalty provisions are almost at the -- very close to the backstop price.

So they would be subject to penalties, in addition to which if the CAISO determines that they have insufficient resources, they can allocate them CPM costs. So they could be double penalized if they come in short for RA.

CHAIR WEISENMILLER: And what is the year where the CCAs are supposed to start flipping to long-term procurement? Is that -- out of 350 is 2021 or --

MS. KITO: So I am not an RPS expert, but my understanding is that begins in 2021. I'm not sure when the compliance date would be. I would suspect it would be closer to 2024 or 2025, but I could get back to you on that.

CHAIR WEISENMILLER: Okay. That's fine. Thank you.

MS. KITO: Sure.

MS. RAITT: Thanks, Michelle. Next is David Vidaver from the California Energy Commission.

MR. VIDAVER: Good morning, Commissioners.

David Vidaver, with Energy Commission Staff. I've been asked to present an overview of Recent and Planned Natural Gas Generation Retirements, a far more mundane issue than those being dealt with by the three presenters which preceded me.

Here we go. The first slide presents just an overview of retirements over the past eight years. We've retired about 10,500 megawatts to date of natural gas-fired generation. That's a turnover of about a quarter of the state's gas fleet.

We should now that we've replaced that with about 8500 megawatts. So we've got about 2,000 megawatts less gas-fire generation capacity than we did eight years ago. The labels are economics and OTC.

Economics is merely not OTC, and any plant that was subjected to a once-a-year cooling compliance deadline is represented under OTC. One can argue that early retirement of some of these plants prior to their compliance deadlines is more of an economic issue, but I didn't want to sit there and try and figure out which plants were retiring in advance of -- or which units were retiring in advance of their deadlines just to apparently stagger replacement capacity at the same site, and which were actually sort of driven out early by poor economics.

So a small share of this 10,500 megawatts is actually repowering Scattergood and Haines 5 and 6, Scattergood 3, the LADWP units were repowered on site, but that's included in these numbers as of retirement.

The numbers for a 2017 show retirement of 3,500 megawatts, but that doesn't reflect year over year capacity availability, summer to summer. Most of the retirements in 2017 occurred prior to the summer.

The significant retirements were Pittsburg, Moss Landing 6 and 7, the old units, and Encina 1, totaling about 2600 megawatts of OTC capacity. Inland Empire 2 retired four cogeneration units totaling about 230 megawatts retired, and the two of the Calpine peakers that were not deemed necessary by the ISO for local reliability, King City and Will Skill (ph. *18:29:27), were also retired.

We are about halfway through the OTC retirement cycle of roughly 20,000 megawatts capacity. In 2018 Mandalay 1, 2 and 3 have already retired. Mandalay 1 and 2 were once-through cooled. Mandalay 3 was not.

Etiwanda 3 and 4 are retired, I believe within the last couple of weeks. And you'll notice, Ormond Beach 1 or 2, Ormond Beach would like to retire in advance of its OTC compliance deadline, but as both the ISO and Michele mentioned, one of those units is needed for local reliability, and will either be picked up in the Resource Adequacy Proceeding, or will be backstopped by the ISO.

We're going to continue retirements for another couple years, most of them pursuant to OTC. Perhaps a better labeling for this slide is not planned retirements, but planned for retirements. There is nothing in here about something that might retire because of poor underlying economics that hasn't already been brought to the attention of the agencies.

We have included in these numbers the units, Calpine units, Metcalf, Yuba City and Feather River, which the ISO found necessary for local reliability, and the CPUC has asked PG&E to solicit replacement, preferred resources in sufficient quantities as to obviate the need for the gas plants.

So those are included as retiring in I believe 2019 in these numbers, along with Ormond

Beach. Of course, they won't retire if they're still deemed -- if they're picked up under RA or they're still deemed as necessary for reliability by the ISO and are picked up under backstop.

There's small amounts of planned -- or of OTC retirements in outer years. They total about 1500 megawatts. They're the three LADWP plants that are -- have compliance deadlines. There's 2014, 2025, 2029. There are remaining units at Scattergood, Haines and Harbor.

Whether or not those will be replaced with gas-fired generation is still up in the air. LADWP is currently conducting, and I believe just finishing, an OTC study, which is designed to shed light on the extent to which preferred resources can replace all or part of those gas-fired resources.

The radial nature of LADWP's system makes generation at the end of the lines that run into the south through the LA Basin necessary, and they have -- apparently have substantial -- there are must-run issues associated with all those facilities and are looking at those, I assume as part of this study.

And as I said, none of these numbers include any gas-fired plants, which may realize that expected revenues don't cover going forward, capital costs and ask the ISO if they can retire. As far as the different types of plants that have retired, we see that we're about halfway through the OTC cycle, 7500 megawatts retired. 8400 megawatts remain to be retired.

Come on cycle in combustion turbines, which just mean not OTC plants, we have about 2500 megawatts of capacity retired and another 1100 planned or planned for by the regulatory agencies, and we've had 13 cogeneration units retire, totaling about 500 megawatts.

And this shows the relationship between retirement and plants being in disadvantaged communities. We've looked at the -- those plants that had a score of 75 or more under the CalEnviroScreen 3.0, and we see that a large number of retired facilities are indeed in disadvantaged communities. Many are not.

There are a share of plants that aren't -- for which we can't determine whether or not they're in disadvantaged community. From what I understand, they're in a census tract that doesn't have sufficient population so as to generate a CES score.

We asked Cartography to look at neighboring census tracts and there sort of all over the map.

Cardinal Cogen retired. That's on the Stanford campus. So it has a relatively low CES score. There are other facilities that are -- well, the census tract doesn't allow for development of a score.

The nearest populated areas are indeed disadvantaged communities. The resources for which we don't have scores are Encina and Scattergood, El Segundo, Alamitos and United Cogeneration, which retired its outfit at the San Francisco Airport.

And then just a brief summary. In conclusion, we're obviously going to witness plants continuing to retire for economic reasons. The state plans on replacing those plants, to the extent possible, with preferred resources.

As the ISO intimated, increasing ramps will result in a substantial need for fast-starting, low-PMN, fast-ramping resources, and the extent to which we can develop such resources that are alternatives to gas-fired generation really dictates how quickly we can retire existing gas-fired facilities. I think I beat the clock.

CHAIR WEISENMILLER: Good.

MR. VIDAVER: Are there any questions, sir?

CHAIR WEISENMILLER: Well, I was just going to footnote. Obviously, along with the gas units we have a couple of large nuclear plants which are retired or retiring, and I would assume there's a fair number of old QF facilities that are not going to get QF contracts going forward.

So whether they may survive or not or retire is the question. So I assume there's a certain amount of small renewable retirement also in this mix, although the fleet's changing pretty fast. Thanks.

MS. RAITT: Okay. Thanks. I'd like to just go ahead and let our morning speakers sort of find a seat in the audience, if you'd like, and we'll move onto our next speaker, Amber Mahone, from E3.

MS. MAHONE: Well, hi, everyone. I'm going to change gears here a little bit. We spent the morning getting a really good overview of the current grid in California, and I want to get out our crystal ball or our binoculars, however you want to think about it, and look forward out to 2050, so kind of setting aside the current situation and looking forward to what would it take for California to meets its greenhouse gas reduction goals.

And I'll be talking about this in the

context of a study that we recently completed with funding from the Energy Commission's EPIC Program. The paper was recently published called -- it's called Deep Decarbonization in a High Renewables Future, and the publication number is up there if you want to look it up and find more details.

It covers an economy-wide view of meeting California's 2030 and 2050 climate goals, but today I'm going to focus on the implications for renewable integration, in keeping with our topic for the day. So as part of this work we worked with a model called the PATHWAYS model, which is a tool that we developed at E3 to look at greenhouse gas reduction scenarios.

And we evaluated three different types of scenarios as part of this project, a reference scenario, which is the black dotted line you see across the top here. This is total greenhouse gas emissions in California going back to 1990 and out to 2050.

And the reference scenario reflects pre SB-350 policy, so sort of California's energy policies circa 2015, 2016, say. The second scenario, SB-350, looks at the impact of a 50 percent RPS by 2030 with no further additions in renewable generation after

2030.

And it includes electrification of vehicles associated with the Air Resources Board goals. And then we looked at 10 different mitigation scenarios that are the gold line there that meet the state's 2030 and 2050 emission reduction targets, which I think probably everyone in this room is familiar with those, but it's a 40 percent reduction in emissions by 2030, relative to 1990 levels and an 80 percent reduction by 2050.

So what I want to focus in on is those mitigation scenarios. Now, in this project we looked at -- we used two different models. So the PATHWAYS model is the economy-wide scenario tool that allows us to calculate total emissions for the state, given a set of input assumptions about the physical transformation of the energy economy, how many electric vehicles, how many electric buildings, how many megawatts of renewable power.

And what we did was we took our -- one of our mitigation scenarios that meets the state's 2050 climate goals, and we took the electric loads that result from that scenario and the electric sector GHG emissions that result from that scenario and use that to populate our resolve model, which is an electric sector least-cost capacity expansion and dispatch model, and we used that to look at a little bit more detail about how the electric sector might operate and what the least cost capacity build might be in order to meet those loads.

So just the PATHWAYS model was sort of most recently used in the Scoping Plan by the Air Resources Board to look at meeting the state's 2030 goals. For this project we expanded it out to 2050. The resolve model has been used at the California Public Utilities Commission in the context of their Integrated Resource Plan.

Prior to that it was used by the CALISO as part of their look at SB-350 regional integration. For this study we took the framework of that model and, again, we expanded it out to 2050. So really long run, kind of big picture look at meeting the state's long run climate goals.

So I want to focus in on one of those 10 scenarios that I mentioned, which is a high electrification scenario, and just kind of stepping back -- I mention these -- they're economy-wide scenarios, although we'll be mostly talking about the implications in the electricity sector.

There's really four key pillars within our framework of what's required to meet the state's climate goals. The first is energy efficiency in conservation, and that's true across all sectors of the economy, in transportation, buildings, industry.

The second pillar is electrification, and that's electrification primarily of transportation, but in many of our scenarios it's also electrification of buildings, and in some scenarios it's also electrification of some industrial end uses.

Low carbon fuels is in this context, I mean, all energy provided -- being consumed in the economy, so percent of primary energy being served by zero carbon energy gets to 70 to 80 percent zero carbon energy by 2050 in our mitigation scenarios, and that's for -- that's encompassing both electricity, as well as transportation fuels and all other fuels.

And then reducing non-combustion emissions is the final pillar. Other categories in that pillar could include reducing emissions from land use. So if we just dig in a little bit more to that third pillar on low carbon fuels, there's really two components here: what's happening in electricity, which is on the left, and what's happening with our liquid and gaseous fuels, so gasoline, natural gas, which is shown on the right.

And the three scenarios that you're -- that are being shown here, I apologize, they're not labeled. But the black dotted line is, again, our reference scenario. The green line is, again, our SB-350 scenario and the gold line is the mitigation scenario, which in this case is our high electrification scenario.

And you can see that by 2050 the emissions intensity of electricity is pushed almost to zero; not precisely zero, but very close to zero. And the emissions intensity of our liquid and gaseous fuels doesn't go down by quite as much.

Total demand for those fuels does go down significantly, but in this scenario, at least, we saw some limits to the availability of sustainable biofuels, and that forces us to reduce the emissions intensity of electricity even further.

So there's sort of a tradeoff there between how much we have to rely on renewable generation to decarbonize the California grid, versus using biofuels or other sources of zero carbon energy.

The other pillar that I wanted to delve into a little bit more deeply is the electrification pillar. And in our high electrification scenario we see a really rapid transition of the state's transportation fleet, as well as the building equipment to electric end uses.

And what you're seeing here on the left, this is percentage of new sales of residential space heating equipment. And you can see that by 2040 almost 100 percent of the new sales of space heating equipment in this scenario are electric heat pumps, as opposed to today where almost 90 percent of the state's heating is from natural gas.

A similar story for light duty electric vehicles. We have a mix here of plug-in hybrid electric vehicles, battery electric and some hydrogen fuel cell vehicles. This is -- you know -- these are two end uses, but we see similar transitions toward electrification in the commercial sector, in water heating and in other types of transportation, so trucking, buses and some off-road equipment, as well.

So all of that results in a pretty significant increase in total electric demand in these scenarios that achieve the state's long-term climate goals. This shows electricity demand in California over time from 2015 through 2050, and our high electrification scenario.

And the bottom bars across the bottom there are agriculture, industry and sort of conventional electric demand in buildings. And these wedges that you see growing over time and really increasing in the 2030 to 2050 time frame are new electric loads coming from the electrification of buildings and transportation.

And so in this scenario I think we've increased total electricity load by something like 60 percent relative to today. So a really dramatic transformation of the electric grid is entailed here. So how do we serve that load reliably while also reducing carbon?

In this scenario we get to about 95 percent of total annual electricity generation being served by zero carbon resources, which is in this case renewable power and existing hydro. So we're left with only about five percent of generation being provided by natural gas.

Now, we've looked at different generation mixes as part of this analysis. One of the lower-cost scenarios that we found included significant expansion of out-of-state wind after the 2030 time frame. So we have 44 gigawatts of out-of-state wind helping to balance the in-state solar, which is -- that would require probably a pretty big regional integration effort and a variety of other changes to make that happen.

But we do see pretty significant benefits from having that renewable diversity in the portfolio. The natural gas capacity factors are dropping dramatically in these cases from about 40 percent today to about five percent by 2050, although we'll note that we assume that a significant amount of the state's natural gas capacity is available to provide reliability services in these case.

So even though they're not running very often, they are still essential for reliability, absent a major technology innovation. So we also looked at the impact of flexible loads in these scenarios, and this is a pretty busy table, but it's just sort of showing the assumptions that we modeled in this particular case, which is that we have these electric end uses, you know, water heating, space heating, electric light-duty vehicles, and we assume that a percentage of those loads can be shifted forwards or backwards by a given number of hours, two hours or three hours.

And in our mitigation case we assume that by 2030 we can get 20 percent of those electric end uses listed here to be flexible within a two to three-hour time frame, and by 2050 we can get 80 percent of those loads to be flexible.

Now, this isn't necessarily a forecast of what would happen. This is a scenario where we're testing, you know, if this were to happen what would be the impact of that. So I would certainly say that a more precise characterization of the ability of flexible loads is necessary, and this work was not meant to capture all of the complexity and depth of the potential for flexible loads in electric end-uses, but we do frame [sic] that given these assumptions, our flexible loads are very valuable.

So this shows an example of two days in spring in our high electrification scenario in 2050. And on the left what you have is the high electrification scenario with those 44 gigawatts of out-of-state wind, a whole bunch of in-state solar and some storage, we see about nine percent curtailment in 2050 in that sort of best case, optimistic scenario.

In a less optimistic scenario with less flexible loads, renewable curtailment increases to

22 percent, and you can see that we also ended up -- the purpose there is energy -- battery storage, and we ended up needing more of that, as well.

So I need to sort of go quickly here, but there's a lot of exciting results to share. The bottom line is that renewable integration solutions save a lot of money, and make the system more operable in terms of lower levels of curtailment, lower needs for battery storage.

So the case on the left is our sort of most optimistic, best case, high electrification scenario with a diverse mix of renewables and a set of flexible loads available. And on the right we have the sort of other extreme where we don't have as a diverse of a renewable portfolio in-state solar resources primarily, less flexibility. We need a lot more battery storage and it increases the cost of the scenario.

So I think I have to skip this, but I'll just conclude that in summary we find that California's climate goals will require higher levels of electric loads in order to reduce carbon, even with aggressive energy efficiency.

We'll need 85 to 95 percent zero carbon electricity, not necessarily zero carbon to meet an

80 percent reduction by 2050, but very high levels of zero carbon electricity. And renewable diversity and renewable integration solutions will be critical to reducing over-generation of renewables and containing costs.

And there's a whole suite of renewable integration solutions, and we find that we probably need all of them. So thank you very much.

CHAIR WEISENMILLER: Amber, obviously, these are scenarios and not forecasts, but do you have a sense of how the uncertainty grows over time, you know, as -- you know -- I would say we were trying to at least get some markers for the 2030 to 2050 time. Do you have a sense of --

MS. MAHONE: Well, uncertainty on which metric?

CHAIR WEISENMILLER: Cost, I would say.

MS. MAHONE: On cost.

CHAIR WEISENMILLER: Yeah.

MS. MAHONE: Yeah. I mean, it certainly gets hazier the farther into the future you look. And you know, one of the things that we're already seeing is if we look at really aggressive cost reductions in wind and -- or sorry -- in solar and storage, that reduces the sort of delta between the high out-of-state wind case and the in-state solar case. So there's quite a bit of uncertainty, I would say, on the costs here.

COMMISSIONER McALLISTER: Thanks, Amber. It's good to see this updated.

And a question just on the range of flexibility options on the demand side, or really, on the distributed side, I would guess, I'd say I guess it would be better to say.

You know, how much have you delved into -- you know -- how much of this is turning off heat pumps and things like that, versus shifting actual load verse -- you know -- and what are kind of the policies that you envision driving some of these changes?

And maybe you have -- you don't go down to policy level and that sort of thing, but you know, certainly, you know, my feeling is that a lot of demand response could be very cheap if the systems were replaced to make it happen, versus sort of a more widget-based, you know, install these technologies and put timers on them.

So I guess I'm wondering sort of how much your scenarios dig into those kinds of details.

MS. MAHONE: Yeah. So in general, we find the biggest value in flexible loads in these long-term, high renewables cases come from the ability to shift loads, not so much the conventional load-shedding, demand response type of programs.

And so that's, you know, the ability to, you know, preheat your water heater or precool your home. Basically, anything you can do to move the loads towards the middle of the day when the solar is available in order to reduce renewable curtailment or the need for more costly energy storage is where we see the biggest value.

COMMISSIONER McALLISTER: So those --

MS. MAHONE: But I think there's certainly lots of other value streams there in terms of providing ancillary services and conventional load-shedding.

COMMISSIONER McALLISTER: For sure. So but you're -- in terms of the ability, the scale of those kinds of resources to create the load shapes that you showed, you think that capacity at that scale is there?

MS. MAHONE: Yeah. I don't think it's a panacea, and I think that, you know, the shifting loads on its own won't provide the whole suite of renewable integration solutions that we're going to need, but I think it's a really important piece of the puzzle.

MS. RAITT: Thank you, Amber.

So next, we'll move onto the regional portion of the day, discussions, and Neil Millar, from the California ISO.

MR. MILLAR: Thank you. Today, I'll give a very brief update on the Informational Study the ISO is doing in partnership with *18:57:26 Power, as well as LADWP, on looking at the possibility of increased capabilities for transfers of low carbon electricity from the Pacific Northwest to California.

Now, this study was initiated as an informational study in our 2018/2019 Transmission Plan at the request of this Commission, as well as the Public Utilities Commission, through a letter sent to *18:57:50.

We have been working forward on primarily the two issues. One is to evaluate options to increase the transfer capability of the system that are bringing such resources to California, and also potentially return them, and also to assess what role AC and DC interties can play in helping to displace generation whose reliability might be tied to the Aliso Canyon situation. So we're working on the two of these issues.

Now, the biggest issue here is that the study scope itself has been getting a lot of attention as we move forward. The scope is really focused on four different aspects. As they're set out here, there's the transfer capacity of the AC and DC systems itself, the dynamic transfer capability on the AC interties.

As well, the third item is to explore the automation of manual controls on key BPA infrastructure that can impact our ability to make sure of resources and address issues in particular, like shaping and ramping.

And the last issue is also -- which depends largely on the progress of the first three -- is to further explore assigning resource adequacy value to firm non -- or zero carbon imports or transfers as we move forward.

Now, the biggest chunk of work to date has been focused on the study plan itself. The analysis will only actually start when the base cases are ready through the rest of our annual planning cycle. So we did put considerable emphasis working with our stakeholders on the study plan as -- make sure we were well positioned on that.

In addition to the public stakeholder call and comments and response to comments going back to April 26th, we've also been working with the other owners of transfer -- of transmission capacity on the task beyond Bonneville and LA.

So that's also garnered a lot of interest. So we have quite a few people participating in the refinement of the study plan, getting input from the other capacity owners. Now, the study plan itself is really identifying the horizon, the assumptions we're using, methodologies and the scenarios.

And we are studying both north to south transfer capability, as well as south to north, to explore not just acquiring resources from the Pacific Northwest, but also, the shaping concept. So the studies are focusing on both of those issues.

Just touching on each of the four components, and I'm aware of time so I'll try to move through this very quickly. The AC/DC system studies are focusing both on a short-term and the longer-term aspect, looking at very modest increases in the short-term, but also, taking on some of the longer-term interests, including perhaps a bit more cursory look at potential greenfield projects.

And this is where we'll also be wanting to come to better terms with the issue of where there is existing congestion showing up on the California-Oregon interties, is that real physical congestion or is it a scheduling, marketing indication that could be addressed without the need for infrastructure.

On the second item, increasing dynamic transfer capabilities, BPA has been moving forward on the increase of the dynamic transfer capability, 400 [sic] megawatts on their own -- well, in partnership with others, but they've been moving forward on that effort.

In this emphasis -- or sorry -- from 400 to 600. I mis-spoke there. What we'll be doing in this initiative is looking at the potential benefits of further increases and if there are any other potential requirements inside the California grid that would need to be maintained, and we'll be updating stakeholders, as well, on any further progress that BPA have been making.

The same implication here is actually on the control automation of the DC intertie. This is an issue that BPA is looking at, and we will be using this forum to keep stakeholders informed of what's happening there, as well as looking at the potential benefits of further enhancements.

And the last issue, assigning a resource adequacy value to imports, this is really looking at how we can make the best, not just physical, but recognize the benefits of any additional physical capabilities, and actually assigning a resource adequacy component to the increased capability, and that is something we see needing to coordinate with the Public Utilities Commission on, but really getting going on that when some of the other actual study work is a bit more advanced and we can frame the conversation a bit more effectively.

And I've just put the schedule out here. Last, this is tied to our 2018-19 Transmission Plan Schedule. So we are looking at presenting results at our November Stakeholder Session, preliminary results, that is, and final results when we present and then seek approval for the annual transmission plan.

MS. RAITT: Thank you. So next, is Doug Marker, from Bonneville Power Administration.

MR. MARKER: Thank you, and Mr. Chairman, I appreciate the opportunity to be here for Bonneville Power Administration. We came down last year for your Workshop, and Kieran Connoly, our Vice President for Generating Supply.

And what we tried to do was present a broad context for the role of BPA, and particularly the value of the flexible hydro in the Northwest generating system for helping to address the issues that you're looking at in this.

And so I wanted to give an overview or an update from that presentation last year, and in particular, how the work that Neil just described fits into our broader strategy. As a reminder, Bonneville Power Administration is a federal power marketing administration in the Department of Energy.

We manage the output of -- market the output of 31 federal dams and one nuclear power plant in the northwest. We operate three AC interties into California and the DC, direct current intertie, which goes from the Columbia River directly into Los Angeles. So these are -- total about 8,000 megawatts of transfer capacity.

As we described last year, we're responding to an evolving electricity market in the west, with greater -- with state goals emphasizing renewable generation. And as the market has been changing, we're looking at the long-term strategic objectives for BPA.

Focusing on adapting to the new marketplace and operating a commercially successful business, two of the issues that I wanted to highlight are just the need to modernize the federal power and transmission system, and to obtain more value for the flexibility of the hydro system.

Towards that end we are embarking on a grid modernization effort, which we're discussing with our stakeholders today in Portland to go through a whole series of tasks to improve the capabilities of the transmission system to operate in real time, and to better integrate variable renewables.

We're focusing on automating processes, incorporating real time data and analysis, and increasing our visibility for the loads and resources and flows to improve our abilities to operate better in real time, and by doing so, integrate renewable resources.

As we discussed last year, we see greater opportunities to participate in the western markets. Over the last year since we were here, more northwest entities have joined the Western EIM, and we are learning from their experiences and we are now contemplating joining the Western EIM, and we will be holding a workshop on July 24th to explore that with our stakeholders.

It'll be a long process for us and it's going to depend on the cost benefit for doing so. But this is another step at a greater integration between the northwest market and California. Neil went through much of the detail.

I did want to stress that we are cooperating in the study that you called for, for both the California ISO and the Los Angeles Department of Water and Power. We're looking at the issues that Neil described with DTC, sub-hourly scheduling, operational and physical expansions, and some of the work that I describe in the grid modernization efforts directly support that.

What's important for me to stress here, especially in this venue, is that work relies on collaboration with our partners in the northwest, the ownership partners on the northern ends of the interties, as well as our continued relationship with the California ISO and the southern intertie partners.

That's very important to us and so we're -- as we're engaging directly with the ISO we're also trying to stay tied in, in the northwest. And finally, to the end of finding more value for flexible hydro, last year when we were down here Kieran Connoly described that we market 16-hour blocks of hydro right across the belly of the duck, as was discussed earlier, and if we can find more value to shape that so that we're better able to meet those ramps we think there would be more value, but we have to figure out how to do that.

So one of the concepts that's being explored are the day-ahead market enhancements that the California ISO has initiated a stakeholder process for. So we're very supportive of that work and engaged in that. So that is another example of the improvements that have been made since last year as we move forward on the strategies.

So that's a quick overview, and Mr. Chair, I'd be happy to answer any questions.

CHAIR WEISENMILLER: Yeah. And I wanted to obviously thank the ISO for responding to particulars of my letter. I think, certainly, we're looking for solutions on Aliso Canyon, and certainly appreciate BPA and LADWP's participation in that effort.

I think, again, it's a way to reshape the way the West Coast Grid operates and look at, you know, the opportunities today. I mean, obviously, these relationships go back to, you know, I would say the '60s at least.

And you know, I guess, actually, one of Nixon's first actions was to stop the second DC line from going into construction. So anyway, it's certainly time to reexamine the opportunities. And I think BPA's looking at joining EIM is certainly an exciting possibility, if that goes forward.

And I think at the same time, the day ahead market and the transmissions capability I think can provide lots of value to both areas. I think part of our challenges will probably be the allocations of cost and benefits not only between the Pacific Northwest and California, but among the various parties in both areas.

But again, I think a lot of opportunity here and, you know, you've heard how the world's changing. Obviously, as we add more and more renewables, also, prices in the west will tend to head south, and so it's a good time for Bonneville to figure out how to maximize its value and its revenues out of these new opportunities.

So again, thanks for being here. Send my best to Elliott. All right.

MS. RAITT: So that's all our morning speakers. So we can go ahead and break and come back at 1:05.

(Recess at 1:01 p.m., until 1:07 p.m.)

MS. RAITT: All right. So okay. Welcome back to our Workshop on Renewables, Integrated Renewables. And we're going to be talking about integrating solar, and the first speaker this afternoon is Lou Fonte from the California ISO.

MR. FONTE: Good afternoon, and my name's Lou Fonte. I work at the California ISO. Oh. Yeah. And my name is Lou Fonte. I work at the California ISO, and the purpose of my brief discussion today is to just talk about some behavior that we're seeing with inverters that are connected to the transmission system.

Now, I want to make the distinction, it's not low-voltage. It's the high-voltage stuff. And I'm going to try and do this in six minutes. So let's see if I can do that. So what's happened is last -- in August of 2016 there was a fire down in the Southern Cal area call the Blue Cut Fire.

This fire was burning underneath some transmission lines, and what typically happens in a situation like that is that smoke comes up, gets into the lines and then the lines cause a short-circuit or we like to call it a fault, and that puts a brief disturbance on the system.

And what we noticed is that we lost a significant amount of solar PV generation during these events. The -- we got together with Southern Cal Edison and we talked about this stuff. We did an investigation, and based on what we found we thought it would be a good idea to take it to NERC, which we -- to WECC, which we did, and then from there we talked with WECC and WECC said, you know, we really think this should go to NERC.

So it did and then NERC looked at the results and said, you know, we're going to form a task force to look into this. So all of that happened around January of last year. And since that event that happened in August of 2016 we've had about 13 more.

There were several on the same day, and the amount of generation that we saw, that dropped, varies. It depends on the type of default and how much solar is on at that time of the day, but some of the amounts are significant.

You know, 1178 megawatts was the one that started our investigation. That's -- just to put that in perspective, we hear the term, you know, 100, 200 megawatts. Well, 1178 megawatts is the equivalent of one unit at Palo Verde. So you know, it's not trivial.

So the task force that was created to look into this, it's got a fancy name, the IRPTF. I guess everyone uses acronyms these days. That stands for the Inverter-based Resource Performance Task Force. And we started by doing a deep analysis of the Blue Cut fire event.

That was the event that occurred in August of 2016. And based on the data that we were able to look at and what we were able to piece together, we determined that there are a couple of things that happened.

One, there seemed to be a good amount of inverter-based generation that tripped due to what it perceived to be as a frequency error, but it wasn't. It was the way the inverters were programmed to make these decisions.

And so we worked very closely with the inverter manufacturers. We've come up with a work around, which basically is coming up with new settings and associated time delays with those settings.

And the inverter manufacturers went out and instituted those changes and I'm happy to say that since they we haven't had anymore instances of inverters dropping offline because of a frequency calculation error. So we consider that one to be mitigated.

There are two more items that we're currently working on and they are very much interrelated. So looking at the slides, it might be a little bit confusing, but the two items are something called momentary cessation and the other one is tripping due to transient over-voltages.

So momentary cessation is a mode of operation where the inverter senses that it's not operating in the system at -- where it should be in the normal parameters. And what it does is it just momentarily ceases to operate.

And that's basically -- we used to call it blocking, but now it's got a fancy buzz term called momentary cessation. But in effect, momentary cessation is turning generation off. So it's not a trivial thing to consider.

There are several things that cause it. The most common thing is where we have a transient low voltage. And the third thing is where we have inverters tripping due to a transient high voltage. So these are the two open items that we're wrestling with right now on the IRPTF.

NERC has issued an alert which addresses both of these problems in very great detail and provides some pretty solid recommendations on what the generator owners can and should do to minimize the probability of having either of these problems.

In addition, the IRPTF has issued a rather comprehensive guideline on how inverters should be configured and what their minimum performances should be and operation and how to set them up and diagnostic equipment.

That guideline has been issued for public comment and those comments are due back to NERC on the 29th of this month. And so what are the issues? I would say that the main complicating issue here is the fact that we don't have national standards.

We do have -- for transmission-connected inverters. We do have national standards for distribution-connected inverters, and we also have Rule 21, but nothing on the national level yet. So what is the ISO doing about this?

Well, there's a couple of things and this is my last slide. What the ISO is doing is, first of all, we're in the middle of what we call and IPE process, which is an interconnection process enhancement.

And what we're doing is through a stakeholder process we're proposing to change the generator interconnection agreements to make, as requirements, the recommendations that are in the NERC alert. So that's our main thing.

We're continuing to work to develop a rather detailed database of solar PV generations so that we know exactly how many inverters are out there and how they're programmed. We have made adjustments to our contingency reserves, and we'll continue to look at that.

We are continuing to work very closely with the inverter manufacturers so that we can get better and more accurate models so we -- our studies will predict better what's happening or what could happen out there.

And finally, the ISO has filed a couple of SARs, which are Standard Authorization Requests at NERC, requesting that NERC undertake the development of a new standard, a national standard, for the -- that governs the interconnection of inverter-based generators at the transmission level. And that is the end of mine.

CHAIR WEISENMILLER: If you know, what entity would develop the standards?

MR. FONTE: Those standards would be developed by NERC.

CHAIR WEISENMILLER: By NERC.

MR. FONTE: Yeah.

CHAIR WEISENMILLER: And any coordination on the international level, let's say Germany or China or other areas which develop --

MR. FONTE: Yeah.

CHAIR WEISENMILLER: -- installing substantial amounts of PV?

MR. FONTE: Well, we -- a lot of the recommendations that are in the NERC second alert, and which we're incorporating into our generator interconnection agreements are based on the German standards, specifically, eliminating this use of momentary cessation. So we based that more or less on what's happening in -- what's happened in Germany.

COMMISSIONER HOCHSCHILD: So I think one point of leverage for us is the eligible equipment list that we have here in California and we maintain at the Energy Commission. It is used by I think 17 other states around the country -- Natalie, am I correct?

MS. LEE: Yes.

MR. FONTE: At least -- yeah. And one of the things that we're going to be doing and I want to push to basically eliminate dumb inverters from that list. So that first -- for the CSI systems that required CEC eligible list inverters, you know, they're hitting their 10-year mark and those systems will begin to need to be -- to replace their inverters and we want to make sure they have voltage regulation and telemetry.

I would welcome any input you have on other requirements that make sense from your perspective, as we move ahead with that. My understanding anecdotally from talking to inverter manufacturers is these features are very, very low cost to add, in the neighborhood of a couple dollars for telemetry and voltage regulation.

So I don't think it's a cost impact and I do think, you know, long-term, as I said earlier this morning, we all need to be good citizens of the grid, every DG PV system should be in a position to help. And I was very impressed, as I mentioned, with the study you did, along with INREL a year and a half ago on that first solar project, looking at all the ancillary services, grid support that a fully optimized, you know, utility scale PV system can provide the grid, including nighttime benefits, as well.

And obviously, we have this fleet, we're going to hit a million rooftop solar energy systems this year, and we want, you know, to be maximizing the grid benefits for all that. So I welcome your input on any other requirements that you think would be suitable for us to consider in order to be on the CEC eligible equipment list.

MR. FONTE: Okay. The only caveat I would have to that -- I fully agree -- but the only caveat I would have to that is that there -- I don't think you can buy a dumb inverter anymore that would be used for the interconnection to the bulk electric.

Yes, maybe from rooftop solar and stuff like that, yeah, that's still an option, but when it comes to the major manufacturers that we see here in the U.S. or even in Germany and other countries, for the inverters that are meant to be hooked up to the transmission system where you're not on a rooftop, but you have maybe a couple of acres or more of solar panels and you're putting out 20, 30, 50 megawatts, those inverters basically all have the features that you're probably thinking of right now.

COMMISSIONER HOCHSCHILD: Yeah, I think that's true. I think I'm talking more for DG, just because I think as we -- you know -- adopt the new Code for new construction, you know, the solar mandate, there's a lot of DG role there.

CHAIR WEISENMILLER: Yeah. No. I remember meeting with one of the solar executives who basically said they used smart inverters elsewhere in the country, but not in California, since it wasn't required here. So the idea is to make sure it's required here.

MS. RAITT: All right. Thank you, Lou.

Our next is Alex Au, from NextTracker, and we have Josh Weiner on the line, on WebEx, to help with any questions.

MR. AU: How do I get to --

MS. RAITT: Just one moment.

MR. AU: My name is Alex Au, CTO, co-founder of NextTracker. On the line, Josh Weiner, CEO of SepiSolar. We've had a tremendous amount of support together with regard to creating a flexible, renewable curtailment with a base load power plant.

So talk a little bit about curtailment and the solutions that NextTracker has come across so far. So just a couple of examples of curtailment. Right now, with Hawaii being 100 renewable in 2045, curtailment predictions of 10 percent, 20 percent, 50 percent are expected.

California found that there is a curtailment of 30 percent in March of 2017, and China, as they continue to expand, are seeing curtailment, as well. And it's interesting to highlight it from this perspective, because when you see the numbers like this it puts things into perspective that most people don't have goals of increasing renewable assets that are even this great in a period of a year or so. Yet, we're hitting curtailment rates.

So the solution that we've come to from NextTracker's perspective and SepiSolar is that renewable assets must be designed from a base load from the very beginning. And we've run a lot of models on this and we've done a lot of RFPs to find the right -- different -- the right, correct inverter partners, software partners and storage partners, and we believe that this can be done with a four to eight-hour storage partnering t PV or renewable assets like wind.

DC coupled with high AC -- DC to AC ratios with de-rated inverters are going to be critical, as well. Once we have selected our inverter partners, we work directly with them to incorporate special firmware that allows us to say, take a 30-kilowatt inverter or megawatt inverter and de-rate it down to 15 or half-megawatt, and that allows us to clip -- instead of clipping, lose the store -- energy from the PV to clipping.

We actually get to keep it in storage and use it at a later time. And again, that creates a very flat, predictable base load output. And the key to all that is the software controls as we integrate the PV and storage hardware so that we have that predictable output, regardless of seasonability and weather.

I put a quote her that really resonates with me. It's an interesting growing pain of our increasingly green grid that we're curtailing the cleanest and newest resources on the grid and leaving alone the 2000 plus megawatts of mostly fossil fuels unreported.

So to highlight kind of how we've built this out at NextTracker is that it's really about creating an ecosystem of software. And so when we have the hardware, like the tracker, which NextTracker has approximately 13 gigawatts worth of deployed product on, as we continue to grow this ecosystem we have selected products like lithium ion storage solutions, as well as a flow solution.

We're looking at, again, building a longer duration, four to eight-hour base load solution. And what's important on that is that we have our software teams working to have that all integrated together, as well as having a NERC's compliant structure around this.

And so these are -- from the standpoint of smart solutions we can connect these. Just as you do with your phone software, we can call into a plant, do an over-the-air software input, software update that allows us to not only improve security features, but also features like voltage regulation and whatnot.

Another point, actually, that I want to make very specific about the smart inverters is I think that it's going to be critical, if it's not already been done, that we include bidirectional inverters on the eligible electric equipment list. That allows us the opportunity to future proof it for energy storage applications.

So this is just a little bit of a visual of what I was talking about with regard to the de-rated inverter. In this scenario we have a 25-kilowatt inverter that allows us to -- has the functionality to handle the power, but if we de-rate it to 15 kilowatts, what happens is that everything above the 15-kilowatt line, it's stored and then used later, at a later time.

And with the use of our smart inverters and working with UL and getting different ratings, we can actually update that through either firmware or over the air -- at a later time at different increments and size them appropriately.

So this is winds for everybody from the perspective of NextTracker provides a flexible curtailment proof solution to get more solar and wind to the customer, less power impact to the grid and a NERC set compliant cyber secure technology to the entire ecosystem, and for the customers' utilities, product and services industry.

This is a little nod to our first solar -- our Tesla Solar City friends, but I like this graph because it really highlights that we all see the duck curve standing alone, and this graph shows the duck curve and how it affects the other power generation sources.

And what's critical to note here, when you look at the base load portions, if we start thinking about renewable assets as a base load, then we can easily start replacing that bottom section with the flexibility of the energy storage. It can come and take care of everything, all the peaks and ups and downs at later times.

The key here, though, is, from my perspective, the industry is extremely immature. And so when you go out and purchase a car -- and then my analogy is when you go purchase a car you don't go to one dealership to buy tires and wheels, another dealership to buy the chassis and another dealership to buy the engine, and then you buy the engine management unit and then bring it all home and write the software to make it all work together.

Again, bringing it back to the point of, we need to start thinking about renewable generation as a basal power plant with the software integrated by the manufacturers to help run that efficiently to the grid, have it connected in a NERC compliant fashion so that we can update and make necessary changes as different issues come up. So it's actually -- that's it.

COMMISSIONER HOCHSCHILD: Alex, can you just give us ballpark since when you include this four and eight-hour storage, how -- just roughly how that affects the PPA price per utility scale projects?

MR. AU: Josh, do you want to take that one?

MR. WEINER: Yeah. So you -- when -- by adding storage you are adding a revenue stream there's usually some *17:33:10 that is evolving when you have *17:33:12 lowering power impact for the grid or just addressing demand on -- or demand charges, or just moving energy into a more expensive time of the day, you're generating a revenue -- or a value doing *17:33:31 as a cost.

So the day price typically goes up as the revenue that you're adding or the value that you're adding by putting the storage in goes up incrementally.

So for example, a store only PPA might be, well, let's just make it another *17:33:50 adding source to it might, for the purposes of moving the solar generation to the best part of the day might end up to be a half *17:33:59.

COMMISSIONER HOCHSCHILD: I understood about three-quarters of that. Alex, maybe you could translate. The connection was no good.

MR. AU: Sure. Let's say -- I'm going to actually say it a little bit differently. The PPAs, a lot of the value comes from predictability, as well. And so to be able to come out and say, you know, between a four and eight-hour we can give you a very flat base, right.

There's a lot of value in that. And at the same time, in coming back in being able to -- if you have the connectivity to the site you can look at weather patterns moving forward and you can insure that there is output from the battery -- stored-up batteries, like say if you're going to have a storm or a weather event the next day.

In our system we've seen a lot of scenarios where when people are buying the components separately that a cloud cover may come across for just even 15 minutes and the batteries continue to charge, expecting it from the renewable assets, than actually it pulls from -- will be able to communicate with each other and make sure that it doesn't do that, so that the output to the grid is a lot more predictable, so.

COMMISSIONER HOCHSCHILD: I understand that's the impact, but I'm just saying, just if -- let's say the project is whatever, $30 a megawatt hour or $25 a megawatt hour, to add the storage, I mean, is it -- are you doubling the price? Is it a -- or just ballpark? What's the incremental cost?

MR. AU: It depends on what technology, but right now it's slightly over double.

COMMISSIONER HOCHSCHILD: Okay.

MR. AU: But we can see within the next 10 megawatts, especially on a slow product, it should be far less than double.

COMMISSIONER HOCHSCHILD: Okay. Great. Thank you.

CHAIR WEISENMILLER: I was just going to note, I docketed two articles, one the German experts saying base load is bad, and going through his experience in Germany, how he reaches that conclusion. The other is a Stanford Cal Tech study that takes 36 year of weather across the U.S., assumes perfect transmission, everything else, and looks at sort of the amount of storage you'd need on solar, or the right mixtures between solar and wind. So anyway, I'd just encourage you to look at those two.

MR. AU: Thank you. I just want to answer that a little bit more directly. After about 10 megawatts of deployment on the supply chain side we've seen the flow numbers for a full storage solution fall below, all in, $300 a kilowatt hour.

MS. RAITT: All right. Thank you.

Next is Sandra Burns from PG&E.

MS. BURNS: Hi, there. So I work in the Structure Transactions Group in Energy Procurement. So I'm talking about how we're approaching these issues from a contracting perspective more than a technical perspective.

And just -- probably seen this slide before -- our portfolio mix last year, we hit 33 percent renewables ahead of schedule, 80 percent carbon free, and we're expecting our renewable position to get even longer, both because we still have new resources coming online that we signed contracts for a few years ago, and also, because we're losing so much load to CCAs.

So we really are not in the position of being a buyer going forward, except for mandated programs, and we're actually in the position of trying to sell our surplus. So you know, the way we looked at the need for operational flexibility has greatly evolved over time.

You know, when we started doing this back in 2004, and really through 2009-10, we weren't worried about having too much energy on the grid in any particular hour, and really, the need to curtail it. We were really worried about people not producing enough to meet their contractual minimums so we would meet our RPS requirement.

So the old contracts prior to about 2011, they don't have any language that allows economic bidding. The only time we can turn someone down is if there's -- over a liability curtailment ordered by the CAISO or by the participating transmission owner.

And then over time we started kind of getting more comfortable with our RPS position, more worried about over-deliveries on the system in any particular hour, and really, the need for us to be able to bid these things economically.

So it started with us having a fixed amount, maybe 100, 250 hours of economic curtailment, and even in the year when maybe we didn't need that much, we still need the option to be able to economically bid -- all time. So we don't have to worry about if we use an hour or curtailment here it won't be available later on during the year.

And then all our contracts going forward, roughly to 2015 and later, they all allow us full operational flexibility. We can bid these things. We can curtail them. We actually paid for the curtailment and then we still have the reliability curtailment that's not compensated.

So just a little bit more detail about how our current contracts work. So the seller tells us whether they're available, what the weather is on the site, and then PG&E is a scheduling coordinator and we are responsible for economically bidding it into the market every day.

The seller is responsible for having the appropriate equipment to respond to our signal, and then we pay. If the meter turns, we pay for metered energy and then we also pay what we call deemed delivered energy. So that's what would have been produced, but for their economic bid not being accepted.

And right now, our standard is the estimate of what would have happened absent the curtailment is the CAISO VER Forecast. So the goal is really to make the seller indifferent to whether we curtail them or not.

And that's proved, like, a very successful model. The sellers have had no trouble financing that in the market, because they have a secure revenue stream. And then the other thing that's in there is they do have an ongoing obligation to comply with all CAISO rules, NERC rules.

So if there was any change to any kind of requirement, they would be required to comply with that. So but we do have this large portfolio of contracts where we don't have the operational flexibility that we might like.

So we've been going through substantial negotiation efforts over the last couple years to get operational flexibility in our contract. We've negotiated another like 1,000 megawatts so far. And the seller benefits. It's a win/win. The seller benefits because they're not in the situation where the CAISO is making prices more and more and more and more negative until somebody accepts a pricing melt, or there's a reliability curtailment in the end.

So they don't face a reliability curtailment, which isn't compensated, and we benefit because we're not being -- seeing even lower negative prices and basically paying to put that renewable energy onto the grid.

And then we've also kind of -- we negotiate those when we can, and in many cases we're negotiating something else anyway, like FERC 764 Amendment. So whenever we are in a negotiation we try to get additional contract flexibility.

I'd say we're probably limited. It's not something that we can do with a change in price, because we do -- we're trying not to reopen the contract for PUC approval. So we're trying to make changes that don't change the risks and rewards for each counter-party too much.

And we do have some challenges. Some of these old contracts, they don't have the equipment and that requires money, and so they're worried about that. Probably the biggest one when we don't have terms and conditions and we try to get people to use our form language, but kind of agreeing to how you compensate for some -- for deemed delivered energy, how you estimate what would have been produced is often prone to lengthy discussion, and then just define contract language about what's a CAISO curtailment that we don't pay for, versus what's an economic curtailment that we do pay for.

You know, it takes a long time to get those words exactly right. The lost PTC for wind is always an issue for those guys. And then basically, the fact that they have to respond to a signal each and every hour creates risks for them, too, in terms of, if you know, there's penalties in the contract if they don't follow orders.

So anyway, that's what we're doing. Like we take every opportunity to try and get additional operating flexibility when we can. And that's it.

CHAIR WEISENMILLER: Yeah. Sandy, a couple of questions.

MS. BURNS: Sure.

CHAIR WEISENMILLER: If you look back at your chart that had the three tranches of contracts.

MS. BURNS: Um-hum.

CHAIR WEISENMILLER: What's the split for your portfolio? Either -- maybe a rough idea of how many megawatts do you have, that you have nothing, you know versus some.

MS. BURNS: I would say it's mostly in the first two.

CHAIR WEISENMILLER: Okay.

MS. BURNS: Yeah. I'd say it's more in the first two, because starting about 2015 we were --

CHAIR WEISENMILLER: Yeah.

MS. BURNS: -- not doing as much procurement. But then, you know, those are the ones we've been negotiating.

CHAIR WEISENMILLER: And what's the total amount of contracts you have?

MS. BURNS: Oh, God, I don't know --

CHAIR WEISENMILLER: Okay. Many? I was --

MS. BURNS: Yeah.

CHAIR WEISENMILLER: -- trying to understand your, you know, contract --

MS. BURNS: Yeah.

CHAIR WEISENMILLER: -- you know, your portfolio management challenges, shall we say.

MS. BURNS: I mean, one thing we have found is, like, a big contract and a small contract has pretty much the same portfolio management challenge.

CHAIR WEISENMILLER: Okay.

MS. BURNS: Like three megawatts or 300.

CHAIR WEISENMILLER: Right, and I could believe it. And have you guys tried to negotiate contracts where people go to smart inverters and start trying to play less energy but more ancillary services?

MS. BURNS: So again, we're really not

buying, except for the mandated programs.

CHAIR WEISENMILLER: All right.

MS. BURNS: So --

CHAIR WEISENMILLER: These would be contracted, renegotiations, I guess, is a better way of putting it.

MS. BURNS: Yeah. It hasn't been the focus, I would say.

CHAIR WEISENMILLER: Okay.

MS. BURNS: Yeah.

CHAIR WEISENMILLER: Thanks.

MS. RAITT: Great. Thanks.

And our next is Abtin Mehrshahi from the California Energy Commission, and Natalie Lee is also here to help field questions.

MR. MEHRSHAHI: All right. Good afternoon, everyone. I'm going to briefly talk about the Energy Commission's Solar Equipment List.

MS. RAITT: We need to turn on the mic, I think, maybe, or hold it closer.

MR. MEHRSHAHI: Let's bring it closer. How about that?

MS. RAITT: Okay.

MR. MEHRSHAHI: Better. All right. Okay. As I mentioned, I'm going to talk briefly about the

Energy Commission's Solar Equipment Lists, and I will start with a brief background of solar equipment lists.

Then I will go to what type of solar equipments we have listed, more specifically, where to list, very general intro about smart inverters under Rule 21. And at the end I will finish with the current inverter listing requirements that are in place.

Senate Bill 1, passed in 2006, directed Energy Commission, in consultation with Public Utilities Commission, called publicly owned electric utilities and interested members of public to establish eligibility criteria for solar energy systems receiving ratepayer funded incentives.

In part, SB1 required that the Energy Commission establish rating standards for equipment, components and systems to assure ease of their performance. By just the mandates of SB1 Energy Commission developed and adopted the guidelines for California Solar Electric Incentive Programs, more commonly referred to as SB1 Guidelines.

The latest version, the 6.1 adopted in November 2016, is accessible by the link that you can see on the slide. Included in SB1 Guidelines is the requirement that all major solar energy system components eligible for ratepayer fundings are required to be included in the Energy Commission's list of eligible solar equipment.

I would like to call your attention to the fact that the lists were created to support solar incentive programs. However, as your Commissioner mentioned, the Energy Commission recognizes that these lists are being used by stakeholders for other purposes, as well.

We have different types of lists, like PV models, inverters, meters, as shown in this slide. The equipment lists contain input and test data provided by manufacturers, as well as other information, such as efficiency ratings, that will be used in incentive calculations.

And the lists currently include a large number of pieces of equipment, as you can see in this slide, and the SB1 Guidelines provide criteria for adding equipment to the list; also, the procedure for removing equipment from the list.

The Energy Commission has the right to remove any equipment from the list for any reason, including but not limited to poor equipment performances, concerns about the quality or lack of manufacturer support for equipment maintenance or warranties.

Okay. Let's move on to information that's specific to inverters. Energy Commission solar inverter list includes two categories of inverters. The first one is utility interactive inverters, that referred to them as traditional or non-smart inverters.

They have been listed since 2007 and are currently still being listed by Energy Commission at this time. The other category is smart inverters. We refer to them as grid support utility interactive Inverters, since it's a term that is being used in UL 7041 Supplement SA, the test protocol for smart inverters, but commonly we refer to them as smart inverters.

Under Electric Rule 21 by CPUC that was implemented for the smart portion on September 8, 2017, any solar project that applies for interconnection to the grid in one of the IOU's territories must use smart inverters.

IOU interconnection process is referred to on Energy Commission list for support of the approval of interconnection applications, something like a fast track interview *17:49:14. Therefore, the Energy Commission extended the procedures and requirements for inverter request in 2017 to support the valuation of the smart inverters.

And to date, the Energy Commission has listed over 400 smart inverters, in addition to 3,000 traditional ones that we have on the list. As shown here, those represent 12 percent of all equipment we have on the inverter list.

Smart inverters. Well, the volume of distribution PV generation system has continued to grow, and the penetration levels have the potential to impact the grid operations. The smart inverters, which can modulate output and communicate actively with the grid operators, are increasingly seen as a way to enhance grid stability and enable wider adoption distributed energy resources, DERs, while minimizing the cost to upgrade -- having significant upgrade to the grids.

The CPUC electric Rule 21 is a tariff that describes the interconnection, operation and metering requirements for generating facilities connected to the investor-owned utility distribution systems for which CPUC has the jurisdiction.

And smart inverter functionalities are being implemented in three phases. As I mentioned, Phase 1 was implemented in last September 2017. A new amendment came out and it will be added to Phase 1. The deadline for that is next month, July 26.

Phase 2 includes default protocol for communications between inverter, DERs and DER aggregators. It is expected to be implemented on February 22nd of next year, 2019. Phase 3, some functions are expected to be implemented on the same date, February 22nd, 2019.

Some other functions will be implemented sometime in 2019. It's not finalized. Okay. As you can see in this slide, this is the overall procedure for submitting the *17:51:20 for inverter procedure. The complete list will have a completed request form, a certificate and test report from National Recognized Testing Lab that it's able to perform the tests under UL 1741, and Rater Inverter Efficiency Form, which the data will be used in incentive calculations. Smart inverters should mention specifically, supplement the same section of UL 1741, both in test report and certificate.

And the last slide is the snapshot of the inverter list, that we have different inverters, smart inverters and non-smart ones, and additional data for smart inverters on the list are included on the certificate date, and firmware that was tested for good support functionality.

And as I mentioned before, there are multiple changes coming up regarding Rule 21 and smart inverter requirements and we're currently working with CPUC, utilities, testing labs and manufacturers to evaluate the need and expectations, for updates to the current list to address these changes, and we will explore whether the list can be further expanded to meet those needs or not, and if yes, how. I was able to finish on time. I will welcome any questions that you guys might have.

CHAIR WEISENMILLER: Yes. So did we distinguish in your list between inverters for transmission versus distribution?

MR. MEHRSHAHI: No.

CHAIR WEISENMILLER: Okay.

MR. MEHRSHAHI: They're all in the transmission side -- the distribution side. I'm sorry.

CHAIR WEISENMILLER: And the question part would be, would it be better if we distinguished and had different requirements for transmission inverters versus distribution inverters?

MR. MEHRSHAHI: That's a good question,

Commissioner. Most of the testing protocols that we have right now is on the distribution side and for lower capacity inverters. For high voltages we don't have, at least as my knowledge, we don't have an accomplished testing protocol for them.

But that's an interesting question and it's a topic we can explore more and evaluate more.

COMMISSIONER HOCHSCHILD: Yeah. I think the Chairman raises a good point, because I think there's two things that I'd like us to accomplish with the list this year. One of them is really reading it so that we don't have dumb inverters on the list.

But the other is, really, how can we make the list more user friendly? There's over 20,000 pieces of equipment. It's three things. It's modules, meters and inverters, and it's mostly modules.

But you know, I think when we do this Workshop I think that's the other question I'd like to get feedback from stakeholders, how can we better organize it. It's a lot to work through and, you know, I'd welcome -- I see, you know, Mel Charles is here from Sunrun and others, you know, who are in the industry, and we'd really like the participation of as many stakeholders, you know, just to give us constructive feedback on how to make it user-friendly.

And do we have a date for that, or we're still working on that, Natalie?

MS. LEE: We've held a date in late August, roughly the 23rd.

COMMISSIONER HOCHSCHILD: August 23rd.

MS. LEE: Late August. We have a hold on that date, but we have not vetted it with our stakeholders yet to make sure it works.

COMMISSIONER HOCHSCHILD: Yeah.

MS. LEE: Then we have a backup, but in the same time frame.

COMMISSIONER HOCHSCHILD: Okay. And really, just, you know, I want to really insist that we get all of the top inverter manufacturers there. We really want their participation.

CHAIR WEISENMILLER: Okay. I had a couple questions. So you mentioned Rule 21 in the PUC. Do we have any process to pull the POUs in to use this list?

COMMISSIONER HOCHSCHILD: So my understanding is it's a condition of interconnection through -- that the PUC requires today, but I don't think the POUs are obligated at all. Am I wrong on that?

MS. LEE: You're not wrong.

COMMISSIONER HOCHSCHILD: Okay.

CHAIR WEISENMILLER: Yeah.

MS. LEE: They are not obligated. Many of them do have similar smart inverter requirements in their areas. Some of the larger ones do not.

COMMISSIONER HOCHSCHILD: Yeah.

CHAIR WEISENMILLER: I was thinking this over-logic on smart inverters should be as applicable in the POU service territories as IOU. And so this might be something that if we reach out, you know, that not only other states use our list, but maybe even the POUs in California.

(Laughter)

COMMISSIONER HOCHSCHILD: Excellent point.

CHAIR WEISENMILLER: And in Rule 21 is there any requirement for not only PV, but say storage or other DER, to use smart inverters, or to use our list I guess is a better way of putting it.

COMMISSIONER HOCHSCHILD: Yeah?

MS. LEE: So it's an interesting question. The list -- the inverters on our list may be used for storage applications. We don't require information on the use. As long as it has the potential to be used in a solar energy system it's eligible for our list.

We have, however, have had quite a bit of interest from the industry in looking not just at the inverter components to storage, but storage itself and whether we should be including -- have that included on our list program.

We've been exploring whether we have authority to do that, but we've definitely heard the need.

CHAIR WEISENMILLER: Yeah. I tend to agree with renewable Commissioner Hochschild. The first step is to get the dumb inverters off, but the others, probably a good time to just step back and do some thinking about the list and how to make it most useful, not just how to -- you know -- trying to weed out the large number and figure out some way to make it more comprehensive, but also just, you know, since there are other, similar -- other uses that this list could be put to that can help drive innovation.

COMMISSIONER HOCHSCHILD: Yeah. I mean, look, the purpose -- part of the purpose of the list is to avoid what happened, you know, with solar thermal in the 1980s where a bunch of fly-by-night companies put crappy products on people's homes that broke, and that set back the clock not just for the solar thermal industry, for the whole solar industry for many years.

And we want to insure what's going in today is high quality, and that's the reason for the list and I think it's been helpful. But we need to kind of push the envelope.

I mean, Alex, I'm curious. You've been in the solar industry for a long time. Do you have any thoughts on the list yourself, off the top of your head? I know you're dealing -- you're in the utilities skills phase mostly now, but.

MR. AU: I agree with you that the list is very valuable. I think one thing that we should focus on is having a way that all the modules and the inverters in the *17:58:29 (inaudible) out there, that could be in a position where you're thinking about it more like a power only perspective, right.

So you plug in batteries to the inverters, the modules and they just -- I think that with this list you can really create that standard, and it's essentially what NextTracker's trying to do, creating that first *17:58:55 (inaudible) platform first, and then everything else can plug in. It doesn't matter what type of technology is there.

I think that the list has an opportunity to really get *17:59:03 off the storage site to *17:59:05 done a lot of work on this one where we're putting different categories in and can -- either a high duty cycle, low duty cycle or middle for batteries, and giving different characteristic requirements out of that *17:59:21 (inaudible) I think some of the frustration is that it's really hard for independent user to go out there and see energy storage over the lowest cost of ownership, especially if we see with that initial first cut *17:59:34.

COMMISSIONER HOCHSCHILD: I think I just heard Alex volunteer to come speak at our August 23rd hearing. Thank you. We accept. But let me just *17:59:41 to connect those two. At this morning's testimony that we heard from E3, this stuff may seem kind of minor and obscure, but it's very significant in terms of making a clean energy future more affordable.

If we get this stuff right it really will save California ratepayers money, and you know, avoid unnecessary expense, which is top priority. So let's see this through and get done with it.

CHAIR WEISENMILLER: Yeah. I was just going to ask Sandy, what's PG&E's -- since you have so many old projects already under contract, what are your incentives or disincentives in terms of switching from dumb to smart inverters, if any?

MS. BURNS: I'd say it's not really our incentive. It's really -- we're buying the power. So we are contractually obligated to buy, you know, the quantities that are promised to us. The seller's responsible for maintaining the equipment.

We don't have any rights to tell the seller to change out their equipment, unless they ask. So in our contracts, if they want to -- we -- our contracts are pretty specific about defining the project and what equipment is at the site.

But that's really to insure that we got what we expected in terms of a thin film solar or something like that. So we don't have any rights to suggest any changes to the facility unless the seller asks.

Like if their inverter dies and they want to replace it, then they need our consent, which you know, not to be unreasonably withheld.

CHAIR WEISENMILLER: But you would not withhold a consent if they did a like for like as opposed to dumb to smart or how does that work?

MS. BURNS: We wouldn't withhold our consent as long as the value proposition was equal or better for us. Kind of our focus right now has been we don't want them replacing equipment that results in more output that we have to pay for, that's above market. And you know, then we're just going to be trying to sell more, right?

CHAIR WEISENMILLER: Right. Right.

COMMISSIONER HOCHSCHILD: Thanks.

MS. RAITT: Okay. So I think we'll take a short break and come back at 2:10. But for our next panelists, if you could come back five minutes early, 2:05, that'd be great. So we'll reconvene at 2:10.

(Recess at 1:56 p.m., until 2:10 p.m.)

MS. RAITT: All right. Let’s get started again. So we're back and we're going to talk about flexible loads and resources. And the first speaker is Scott Blunk, from the Sacramento Municipal Utility District.

MR. BLUNK: Hello. This is Scott Blunk from SMUD. I work on energy efficiency and electrification issues. I extend my appreciation for having me here to speak.

Electrification, we find it incredibly beneficial to SMUD. It's going to reduce our customer's energy bills. Of course, there's going to be carbon savings. It's going to accelerate our fixed cost recovery at SMUD, which essentially is saying that we're able to be rate neutral even at our initial rebate offerings. It's going to create local jobs. It's going to improve our regional air quality and more opportunities to shape the load on our grid.

This table, it's not too busy. It's kind of all of our programs that we're offering right now. I believe there's seven on there. The first four are currently in operation, so that's New Construction Single Family and Multifamily Program. The Single Family is a $5,000 incentive.

The single family existing program is the HPP, so that is heat pump water heaters, space heating and cooking. And there's a $2,500 incentive if you do all of those or if you need a panel upgrade, which is going to be an impediment to electrification.

And then there's a $3,000 incentive just to do a water heater conversion from gas to electric and then the multifamily existing program that's coming on line within about a month.

Then we'll have a midstream heat pump program and a direct install program coming in the first quarter of next year.

So what this slide is showing, this is from our actual customers and what they're using right now. The blue bar is the gas-heated homes and the red is the -- or sorry, the blue is electrically-heated homes and the red is the gas-heated homes. And it's just showing peak demands throughout the year. This has been standardized for a normal weather year.

So it is showing that our peak would, under this scenario for the existing homes anyway, our peak would shift to the winter months. However a lot of these homes that were built in the '70s, these all electric homes have lower quality and quantity of insulation and heat pumps. So we expect with some proper load management and higher efficiency equipment, our winter peak should not exceed our summer peak.

And also kind of as part of our home performance program for our existing buildings, what's not listed on there is another $3,000 incentive to improve the insulation and air sealing of that. And that kind of rolls into kind of helping manage that load, and the flexibility of it that I'll get to it in just a moment.

This slide is really about kind of what it's going to do to our customers and their bills in energy consumption and $CO2$ levels. We expect a slight amount of savings of a hundred and some dollars a year on their energy bills, by going to all electric. And this is for new construction, but we've seen savings for kind of all vintages of existing homes. But new construction costs are marginal, $127 added to go all electric right now. And that includes a very small adder for the gas infrastructure, because that was hard to determine.

So for heat pump water heaters, I'll get to the flexibility part of it. The idea behind the heat pump water heaters is that we will -- so in the morning you get up, you take a shower, you're out of the shower at 7:00. The water heater will not recharge or will not heat the water again until kind of midday when we get to peak renewable generation.

And then with a mixing valve, we can heat the water beyond the desired temperature, normally around 125. We can heat it above that so that during the peak energy demand, the water heater will not turn on again until we've reached past that peak. And we think we can shift about a kilowatt hour per water heater through that and just be able to float through the peak.

So for HVAC, it's highly dependent on the level of insulation and air sealing in the building. Windows are also another major factor. Air sealing is a big deal, because it affects not only the heat loss through the air that's already been conditioned, but air movement through insulation degrades it greatly. So improving the envelope is really important in being able to use space heating to pre-cool or pre-heat a home.

And I talked about some of this. The envelope -- yeah I think I've talked about most of that. So the batteries, with the all-electric home the other advantage is you have more loads on the batteries as they get installed, to where right now through our shoulder seasons there may not be enough demand to actually use all of that battery in the shoulder seasons. So if you have additional electric loads on the house, like water heating and cooking, that will be able to recharge or take advantage of more of the on-peak high generation PV during the middle of the day. And so we'll get better utilization out of the batteries. That's it.

COMMISSIONER HOCHSCHILD: I just wanted to thank you again for joining the tour at the LIBOK (phonetic) Project, the low income.

MR. BLUNK: Oh yeah, you're welcome.

COMMISSIONER HOCHSCHILD: And just to compliment you and SMUD for doing what you're doing. I think it's absolutely path breaking, this new incentive program. In fact, I think my Chief of Staff is going to be one of your first customers. But do keep us posted as that proceeds. I think you're out ahead of the rest of the state in terms of the incentives you're offering. And I'd be very interested to get feedback on some of the lessons learned.

I myself swapped out my natural gas water heater for a heat pump about six weeks ago. It's working great, but I do think it's not something that occurs to people as a priority to do. And then a lot of people are not even aware that the technology is there now. So your incentive program is really well timed and I think well crafted.

MR. BLUNK: Well, thank you. And part of the reason for the high initial incentives was to catch people's attention and kind of try to make this a no-brainer. And after the first two weeks, we've had I think four whole homes converted and fifteen space heating conversions and a dozen water heating conversions after the first couple of weeks. So far looking good, hopefully all those conversions aren't sitting in this room right now. (Laughter.)

COMMISSIONER HOCHSCHILD: Yeah, it wouldn't surprise me. Thank you.

MS. RAITT: Okay, great.

Next is Sabrina Butler from San Diego Gas and Electric.

MS. BUTLER: Hi. I’m Sabrina Butler from San Diego Gas and Electric. Thanks for having me. I'm going to just spend some time talking about our early results from our default TOU transition with our pilot program.

So right now most of our residential customers are on a tiered rate plan, a pricing plan where they're charged by the amount of energy they use. And following with our rate reform program and the 2019 plan by the end of next year, almost 750,000-ish customers will have been transitioned to a time-of-use pricing plan.

These plans give customers what we think is more choices and control, because it allows them to shift their energy use to off-peak periods and lower their energy bill and their energy usage.

So our first -- we're going to offer two TOU plans. One is a 3-peak period and one has a 2-peak period. Our default plan will be the 3-period pricing. We want to give customers all of the options that they have. In terms of where they can't win, they can use their energy. If they want to opt out they can and they can opt out to another TOU plan or they can stay on their current tiered plan.

As part of our default pilot rollout, which we have just finished the rollout we've transitioned the customers in March. We had a really robust communication plan where we started with a 60-day notification, a 30-day notification. And those were personalized plan comparisons. So we took the customer's energy usage for the last 12 months and compared it to each of these pricing plans, so the customer could really make an informed decision.

About 5 percent of the customers opted in early and then we transitioned the rest of them in March. About 15 percent of the customers did opt out and I'll get into some of that in the next slide.

Two of the things that are keeping customers on what we found is we have a risk-free opportunity. So for the first 12 months, they have no risk pricing. So if a customer would be better on a tiered rate, we'll move them back and then we'll credit them the difference, so that it's really risk free. Try it out, see if you can shift your energy usage and ultimately save. You're also not locked into these plans for 12 months. So any point in time in the first 12 months you can say, "I want out of this. It's not working for me." And so you can.

The other thing though was really working is that customers now really do have two ways to save. Before, it's just reduce your energy or do energy efficiency activities. On TOU you can do those things, but you can also shift to an off-peak period or just instead of turning your dishwasher on at 7:00 o'clock after dinner, turn it on at 10:00 p.m. and you will save money.

So I think those are things that customers don't really realize can add up in savings over time. Do your laundry on Saturday morning during the super off-peak period. On the weekends it's until 2:00 p.m. So these are ways that customers can shift their behavior and save money.

So we transitioned about 114,000 customers in March on to one of our two TOU plans. And so far, we're seeing a slight reduction in on-peak period usage from this time last year, just very early preliminary results. We have 15 percent of the customers originally opted out, but we're staying with seeing that 85 percent retention, which is really good. I'll come back and give you more information after summer, because we do want to see how customers really behave during the summer time. Obviously those might be sort of different than with winter.

A couple of things we found out about how customers though were interacting. One point here is the business reply card. You'd think in this time where people want to get online and self-serve they really use this, fill out the form and send it in, which is very interesting to us. Most of the customers did that. A few calls to our contact center and then obviously the self-serve.

The other thing that we did that we're testing is what we call the Extreme Non-Benefiter Campaign. And I use the word of "extreme non-benefiter," but just so we have that in context it's an extreme non-benefiter is one who has a $10 or 10 percent increase annually: $10 a month or 10 percent increase annually.

So what we did with those customers is we actually reached out and did a call-in campaign with them. Wanted to talk them through what this meant to them and their options. And 11 percent of those customers actually said, "Let me give it a try."

Now that 12 month no-risk pricing was very beneficial to them, but they said, "Maybe I can do some things that would actually allow me to benefit."

Now most likely those customers won't be better off, but their behavior changes, what they learn would be very beneficial. But that also gave them just more information and made them feel better about the company, time of use and their choices.

And the things that we're working on in terms of our customer engagement and education, as you can see the reasons for opting out, it was just their concern that TOU will increase their bill. People who actually benefit based on their last risk comparison, said that. So it's saying that customers aren't fully aware, some of them. Obviously some may not be. So that is why we're trying to work on our communication and outreach, so that we can really get to the customers, so again so they can make informed decisions.

And that is all. I mean the last slide is just our rollout plan, sorry. We start in March and the other two IOUs in 2020.

CHAIRMAN WEISENMILLER: Well, thank you.

I know last year the presentation from the PUC staff about the time of use, obviously President Picker was very enthusiastic in part based upon his experience in the SMUD Board and in terms of incenting folks.

So at the same time I think PG&E and Edison both have problems with their billing systems and have had to slow down the rollout.

But again I think for a lot of to encourage more flexible load, this is like a basic step. You really can't get there without time-of-use rates in that mainstream billing system that will accommodate them. And you also need, as you talked, so many very sophisticated campaigns to not just to flip the switch and have everyone go crazy.

MS. BUTLER: It is and our billing system goes in right after we go live with our TOU price plan. It's very exciting.

MS. RAITT: Okay. Thank you. So next is Anna Chung from Southern California Edison. And she'll be speaking via WebEx.

MS. CHUNG: Okay. Thank you, is there an echo?

MS. RAITT: You sound okay from our end.

MS. CHUNG: Oh, great. Okay.

So good afternoon everyone, I'm a Senior Advisor at Southern California Edison and today I'm presenting SCE's Demand Response Auction Mechanism.

CHAIRMAN WEISENMILLER: Hang on a second. We're now having some AV issues.

MS. RAITT: Now, we're having some trouble hearing you.

COMMISSIONER HOCHSCHILD: I wonder if she's -- are you on another phone line with the same --

(Colloquy re: audio issues.)

MS. CHUNG: How is that? Is that better?

CHAIRMAN WEISENMILLER: You want her to do some tests? Say something.

MS. CHUNG: Okay. Thank you. Okay, I'm eating into my seven minutes here. Let me try this again.

I'm going to be presenting the Demand Response Auction Mechanism and the procurement of flexible resources for addressing the --

MS. RAITT: Anna, I'm sorry, I'm going to interrupt you. Are you using a speaker phone?

MS. CHUNG: Yes, I am.

MS. RAITT: Well, maybe we can move on to the next speaker. Would you be able to figure out a way to not use a speaker phone?

MS. CHUNG: I can call in on my cell.

MS. RAITT: Okay. So we're going to try that and we'll move on to the next speaker and we'll come back to you, okay?

MS. CHUNG: Okay. Sorry about that.

MS. RAITT: Thank you.

So we’ll go on to Gabriel Taylor, from the Energy Commission.

MR. TAYLOR: Good afternoon my name is Gabriel Taylor. I am an Engineer in the Building Standards Development Office here at the Energy Commission. I'm also the Project Manager for the Demand Response Section of the Building Codes Update, Energy Code Update.

Today, I'd like to give you a quick summary of the actual demand response requirements that are currently in the Title 24 Code. And then I will go into a little bit of detail on the cost effectiveness metrics for new requirements in the Building Energy Code.

We're talking about the California Code of Regulations Title 24. That's the Building Standards. Part 6 is the Energy Code. That's the portion of the Building Standards that the Energy Commission is responsible for adopting. This is on a three-year cycle, so every three years we adopt new updates to this Code. So it's an iterative process and I'm always encouraging stakeholders to come talk to me, so we can refine the Code that's there.

We just finished an adoption cycle. So we just adopted a new Code and the summary that I'm giving you today is based on that new Code that will go into effect on January 1st, 2020. We've already started talking to stakeholders and started thinking about the next Code cycle, so this is the 2022 code cycle. And that's predominantly what I'll focus on in the cost effectiveness section.

So it turns out that there are actually fairly few sections of the Code that reference demand response. There are approximately four sections of the Nonresidential Code that require certain types of demand response. There are two sections of the residential code that allow certain kinds of demand response. There are no requirements for demand response in the Residential Code.

There's also some minor exceptions for solar-ready rooftop space, but because of the new requirements for solar PV on the rooftops that's much less significant. So I'm not going to cover those today, but if you have certain types of demand response and energy efficiency in combination you need less solar-ready space on rooftops.

I want to emphasize that nonresidential term, as defined in our code, includes high-rise residential. So the term "nonresidential" means basically everything except for the single family low-rise residential kind of house that you're kind of familiar with.

First thermostats in nonresidential structures, if you have a single zone air conditioner or heat pump then you are required to have the demand responsive thermostat. If that single zone thermostat also has direct digital controls, then you're required to have additional demand shed requirements. And any time that you retrofit or alter a HVAC system you're generally required to install a demand response thermostat, if that thermostat's not already there. This is mandatory. This is required.

In the lighting section this is the lighting controls, not the lights themselves, but the controls need to be demand responsive in buildings that are larger than 10,000 square feet and in sections of those buildings where you have more than 0.5 watts per square foot.

I've had a lot of discussions with the lighting industry about this. And it's important to emphasize again that this is the controls themselves not every single individual light bulb, but just the controls. And this is mandatory.

Electronic message centers. These are the large powered billboards. If they're more than 15 kilowatts, it's a pretty significant size, they're required to have -- it's a specific curtailment requirement. It's not required necessarily to have the normal demand responsive communicative functionality, but it's required to be capable of a 30 percent reduction if it received a signal. And this is required.

And finally, there's a general requirement in the new Code that points to open automated demand response communications protocol. So if you're installing a demand responsive control in the structure and you're doing so for the compliance with the Code or for credit under the Code, then it's required to comply with the sections that specify both the hardware and software layer of communications. It's a minimum level of function, a minimum level of communication. It's to ensure that the building owner or operator has that functionality available and that is required.

Moving on to the residential section, if you're installing a heat pump water heater, an electric heat pump water heater, and this an alteration, not in a new building, but an alteration then there are two optional pathways that allow for demand responsive functionality. These are not required. These are options. There are a number of other options here that you can go through if you're doing this type of work.

The two options are either the normal pathway for open ADR minimum level functionality or a NEEA Tier 3 pathway, which provides some other optional including CTA-2045, which is a popular communications protocol for water heaters.

And finally, this is a very rare, alterations of HVAC equipment. And if you have a demand responsive thermostat there is some optional allowance for how you test that HVAC alteration. It's a very rare case and I'm not aware of any cases where this has been used recently. But it is in the code for fringe cases where it's necessary. And it's optional. You can always test using the normal protocols.

So that's it. That's all that currently required under the Building Code, residential and nonresidential.

Now most of this is focused on emergency shed. This is obviously not as useful for renewable integration. This is a vestige of the energy crisis going back more than 15 to 20 years and looking at the type of demand side management that was determined to be cost effective and generally this was an emergency shed or a curtailment type of program.

Going forward, when we're looking at demand response requirements in the code and this applies to both the Building Code, the Appliance Code and the Load Management Standards, which the Energy Commission also has authority to enact we have to ensure that these standards are cost effective for consumers.

An example, and this is something I'm very excited about, we've already started talking to a lot of stakeholders on the equipment and manufacture side is the TOU rates that are rolling out and the utilities have pointed out here. The TOU rates, which the Energy

Commission has been supporting as a policy for well over a decade now and we're finally going to see them coming into the consumers' households. I'm personally already on the TOU rate and I have experimentally moved loads around and I have an electric vehicle and what not. And I found it to be very, very easy and virtually no significant impact on my personal quality of service to move those loads around.

I wanted to bring a whole bunch of pictures of my load rates, but that's probably not pertinent here. But I think it's important to emphasize that the TOU rates provide a cost effective metric that we can use to justify new demand response requirements in the Building Code.

And if the policy support is there, that’s something I'm very much looking forward to discussing with the manufacturers and all the interested stakeholders.

CHAIRMAN WEISENMILLER: Great. I’ll just ask the usual follow up questions in terms of so what do we need to do in terms of any additional training material or stuff for the standards we just adopted as opposed to the next standards?

MR. TAYLOR: The Energy Commission staff is currently working on the compliance manuals. We hope to have those out in a few -- the Project Manager is not here -- but in a few weeks, I believe is the goal for the for the draft documents to be put out for public review. Those will include a number of -- the guidance for how to comply with the standards and those will go out to the stakeholders for review. And then we'll adopt those later.

I'd have to defer the actual schedule to the Project Manager for that timeline.

CHAIRMAN WEISENMILLER: That's fine. I just want to always really make sure people follow through on what we've committed to do to get ready to put in standards rollout, as opposed to getting too caught up in what we could do in the next round.

MR. TAYLOR: Absolutely, there's been a significant amount of urgency getting all those parts put in place.

CHAIRMAN WEISENMILLER: Great. Okay.

Ms. Raitt?

MS. RAITT: Okay. Great, so we'll move on to Arthur Haubenstock from the California Efficiency and Demand Management Council.

MR. HAUBENSTOCK: I'm Arthur Haubenstock. I am the new Executive Director for the California Efficiency and Demand Management Council. Thank you very much.

So we have over 80 members across a broad range of energy efficiency and management issues. Our mission is to support energy efficiency and demand management policies and programs for all Californians to create sustainable jobs, long-term economic vitality, able and reasonably priced energy systems and environmental improvement.

Energy efficiency has been an extraordinary success story for California. While we've had fairly modest growth in energy demand not withstanding our financial stimulation and economic growth if you look at the rest of the country, which hasn't unfortunately enjoyed our economic growth -- well, there we go -- that hasn't enjoyed our economic growth we have done even better. The rest of the country has even over the last 10, 20 years had substantial energy growth.

At the same time, energy efficiency is considered to be one of the most important building blocks in achieving climate reductions and other emission and environmental improvements. This is a graph that I borrowed from NRDC that was looking nationally, but as you can see the first building block, the most important and largest building block is energy efficiency. And the next largest building block is a smarter grid that includes demand response.

These are critical foundational elements for California and the rest of the nation to achieve our environmental objectives for our energy system.

The question often comes up, what is it that energy efficiency and demand response can provide to a flexible grid? And I do think the better question is what is it that it can't provide? And there is the opportunity to provide energy capacity ancillary services, even transmission and distribution system solutions. It ranges according to the technology and the application that we're talking about. But even traditional energy efficiency can reduce the need for transmission upgrades and distribution upgrades, particularly if it's focused.

Traditionally, it has not been. Our traditional energy efficiency programs have not had that kind of program, that kind of focus. The same is true for demand response. But we're seeing a tremendous influx of new entrants into both energy efficiency and demand response that are creating tremendous capabilities. What we're missing is the economic signals and the regulatory structure of the programs that enable energy efficiency and demand response to optimize our system. That's where the Council is focusing its efforts.

One concern that we have had, and I thought it was topical given the nature of this panel, is something that is sometimes omitted when we talk about flexibility for a renewables driven energy grid. We are very much supportive of and in favor of the direction that we are heading in California with the renewables driven grid.

We're sometimes told that, by some thought leaders, that we should not be trying to save energy. We should be using more energy, because using more energy reduces the risk of curtailment of renewables. We think that that's a false equation.

And I want to be very clear. I'm using the ISO's "Duck Curve" graph here. And the ISO has been very, very clear about what the duck curve is and what it isn't. It is a very serious concern. It's something that we need to take very seriously and we have the tools across all the various different technologies and approaches that have been discussed today, to approach it.

But we also have to consider what sometimes gets lost when we talk about the duck curve. If you look at the duck curve in its entirety here, then you focus in. And notice that the on the Y axis there's a pretty big gap between zero and 10,000 megawatts. And what that is, is the sea that the duck is floating on. So the duck is floating on a sea of inflexible resources that are considered to be non-dispatchable, either because of their baseload or because of contractual requirements.

Rather than trying to reduce energy efficiency and increase energy consumption what we should be doing is looking at the whole stack of both supply and demand resources and figuring out what is going to move the ball further in achieving California's energy load. There's a lot that we can do to make the entire system more flexible.

Energy efficiency and demand response can provide much of that. And I was very interested in E3's presentation earlier that talked about how much we can expect through electrification of our economy to increase electric loads and how important it is for that electric load to be flexible to meet California's energy needs.

With that I will say thank you. And look forward to your questions.

CHAIRMAN WEISENMILLER: Okay. I mean, last year we had an LDL study reported where there was thousands and thousands of megawatts of demand response. If you look at the chart that's in the Green Book since San Onofre went out and we did a big push to enhance demand response the numbers have gone down, you know the bottom line. So how do we turn that around? I think in the last IEPR we were characterizing the existing demand response programs as a failure, which is probably a polite term.

But anyway, how do we go from basically declining demand response to that being a bigger part of our resource mix?

MR. HAUBENSTOCK: That is an excellent question. And I think unfortunately some of the dynamics that are focused on in the Green Book auger in the opposite direction. Complexity is not the friend of demand response. We do think that as we move forward with technology it's going to get quite a bit easier.

We're relying on human beings to change their behavior by conscious decisions. It is a very, very slow response. As we heard from the ISO when they need to respond in milliseconds or four seconds or whatever it may be the opportunity to aggregate across a fairly wide variety of users, and to make changes that are so rapid that human beings could not approach that kind of decisions making.

And also that human beings are not ever going to experience those. I was very glad to hear that your personal experience was that your use of demand response programs didn't affect your comfort and safety and well-being and economic activities. I think we will find that across California. But we need to make it easier. We need to make it simpler. We need to make sure that as we have seen changes between load serving entities that these programs are portable. And that people can depend on the investment that they make. That they will pay back over time.

COMMISSIONER HOCHSCHILD: So I just want to double that, because I mean I agree with the Chair. I mean we're failing on this issue. And I just wonder if you have any thoughts about how the state energy agencies are organized around this? I mean, do we need to have a California demand response czar, for example, to organize and push on this? Because the stakes are very high, not just for grid reliability, but also for ratepayer impacts here and I'm just pretty underwhelmed at our headway that we're making on this.

And I'm just curious of your thoughts on in terms of the regulatory architecture around us that we have today at PUC, CEC, ISO, Governor's Office. Do you have any thoughts on how we could be better organized?

MR. HAUBENSTOCK: You're absolutely right that we have far to go. And honestly one of the things that attracted me to come to the Council was the tremendous potential on the work that we need to do in order to achieve it. I do think that there are other jurisdictions that are making better progress than we are. I do think that we need statewide consistent rules and interfaces that will allow very simple interaction with demand response, so that that aggregate value could become a reality.

Whether we need a statewide czar, I don't know. It's a good thought. But I do think that the Energy Commission is in a very good position to be identifying that value that we can achieve to help us identify the regulatory barriers, the market barriers that are keeping us from achieving that value and to figure it out.

I mean there is a little bit of a problem in the diffuse nature of the value. I think the fortunate thing is that the technology is making it easier to attract all those little pieces that add up to something that is valuable, not just economically, but also in terms of grid operations and in terms of our environment.

So we need to be thinking about how we can create that regulatory structure that opens the door for technology. We know that there are lots of technology adopters who are excited about this. A lot of them have failed, because they were not able to get the market opportunity they needed. They weren't able to see the value that they know or can realize the value that they know is out there.

CHAIRMAN WEISENMILLER: Well, we're going to be calling for written comments and so when you do yours, if you do want to suggest this can be the Demand Response Action Plan, we're going to see it.

MR. HAUBENSTOCK: Thank you for the opportunity. I look forward to it.

COMMISSIONER HOCHSCHILD: And I don't know if we were able to get the woman from Edison back on now, but I'd welcome her thoughts on this question as well when she gets back.

MS. RAITT: Okay. Are we ready to go and give it a try?

MS. CHUNG: Okay.

MS. RAITT: Go ahead, Anna.

MS. CHUNG: Can you hear me?

COMMISSIONER HOCHSCHILD: Yeah, much better.

MS. CHUNG: Oh good. Thank you. All right, I guess I don't need to introduce myself still. So the next slide, please?

The DRAM pilot, or the SCE Demand Response Auction Mechanism, starts the process on this vision of a long-term solution for the procurement of third-party demand response.

The pilot allows demand response to come head-to-head against conventional resources and encourages new market participants in DR through annual qualification.

The DRAM provides capacity permits for aggregators to participate directly in the CAISO market. Without DRAM an aggregator could only earn energy payments in the CAISO market. It provides a capacity payment that actually does provide a more level playing field with the IOU DR program.

The DRAM uses a standard agreement for research adequacy without bilateral negotiations. The IOUs are have purchasing capacity in claiming RA credit, also known as RA Tag.

Third parties own the relationship with the customers and the CAISO, but unlike prior IOU aggregator managed contracts, they actually have a relationship with the CAISO, while previous aggregator managed contracts the relationship was only with the IOUs. The next slide?

Okay. This diagram is an illustration of the relationship between the CAISO, the IUOs and the aggregators, otherwise known as demand response providers. It's important to note that IOUs have no dispatch rights, nor do they have visibility to dispatch information. They're not privy to any DRAM participants with pricing, quantity and advanced performance. Next slide.

For DRAM the three products that are available are System Capacity, and that is IOU-wide and can bid into the market as reliability demand response resource or proxy demand response. Providers must bid per the CAISO must-offer obligation for day ahead and real-time markets.

RDRR is emergency dispatch and PDR is economic based.

To qualify as a capacity at local capacity the resource must be located in SCE's LA Basin or Big Creek/ Ventura substation areas.

Local resources must be able to respond to a dispatch instruction in less than 20 minutes. Flexible capacity must be a PDR resource and to qualify for flex RA the resource must be able to ramp and sustain energy output for a minimum of three hours and must bid per the CAISO's must-offer obligation for flexible RA. Next slide.

So how is the DRAM conducted? Well, the DRAM is a reverse auction. So in other words, bids are ranked by the market value. And the lowest price capacity is procured first until the authorized budget cap is reached. The IOUs must procure a minimum of 20 percent residential megawatts.

These are one-year RA contracts with the exception of draft rates for 2018 and 2019. Offers must bid capacity prices by month and megawatt and must include an August bid. Next slide.

This chart displays the grant procurement results by IOU and delivery year for the four DRAM pilots. In 2017, the IOUs were ordered to procure an additional RA for 2019. In addition to the megawatts that have already been previously been contracted in DRAM 3.

As you can look at this chart, you'll see that SCE and PG&E's authorized budgets and DRAM results are very similar. All these megawatts reflect the August capacity.

A flux capacity product is not offered in the first year of DRAM. DRAM 1 provided a system RA only and delivery for seven months, June through December 2016, due to the late launching of the pilot.

In DRAM 4 the IOUs calculated flexible, local and system offers separately. Flex was deemed to have greater value through local. And local capacity was deemed to have greater value than system RA.

DRAM 4 contracts are currently pending approval by the CPUC. And if approved SCE will have approximately 177 megawatts for 2019.

DRAM is technology blind and DR capabilities can be manual or technology enabled, such as smart thermostats or energy storage. We just don't know, and it could be a combination of any of the above. We have approximately 26,000 customers registered with the DR providers in the CAISO system. Next slide.

So flexible RA is still very new and is reflected in the procurement results. DRAM 2 and 3 have very similar results of less than half a megawatt of August capacity. DRAM 4 however shows a big increase in flex RA, most of it coming from Leapfrog Power, an EPR provider, accounting for 20 of the total 20.7 megawatts. Next slide.

So was the DRAM Pilot successful? In 2016, the Commission directed the Energy Division to conduct an independent analysis of the results of the pilot auctions and subsequent deliveries against six criteria. The criteria for assessing the success of DRAM pilots included: 1) that the DRAM engage new viable third-party providers. 2) That they engage new customers. 3) Were auction bid prices competitive? 4) Were offer prices competitive in the wholesale markets? 5) Did demand response providers aggregate their contracted capacity in a timely manner? And 6) Were resources reliable when they were dispatched?

So the ED focused primarily on results from DRAM 1 and 2 for contract deliveries in 2016 and 2017 and included some data from the DRAM's re-procurement conducted in 2017 for deliveries in 2018 and '19.

In a recent status conference and the ED's DRAM Evaluation Update Memo dated just last week the ED's assessment of criteria one, two, three and five is nearly complete. But due to limited bandwidth and resources, and significant challenges were encountered in evaluating the CAISO-related criteria, which is four and six, including data quality issues and internal inconsistencies leading to inconclusive results.

So the ED is pursuing discussions with an outside consultant to continue the assessment effort, primarily focused on the CAISO-related criteria, four and six.

The next step will be a workshop in late July or early August to report out the results of the non-CAISO related criteria. And update the Commission and the stakeholders on the schedule for completing criterias four and six.

And that concludes the presentation on DRAM.

CHAIRMAN WEISENMILLER: Thank you. Do you have a sense if we were trying to go up an order of magnitude of something? This is Bob Weisenmiller again. We've been pushing in the Aliso context for demand response. This looks like it's about 20 megawatts and the question is if we were trying to increase the scale, so in order of magnitude or so do you have a sense of how quickly you could do that?

MS. CHUNG: Do you mean specifically for Aliso Canyon?

CHAIRMAN WEISENMILLER: Well just generally, but certainly in the Aliso context or back in the SONGS context we were trying to scale up pretty quickly.

MS. CHUNG: Right. So if this evaluation were completed June 1st we would hope to have a final resolution or a draft resolution, I'm sorry, about future procurements for 2020.

And on that cap on the megawatts was to be 1 gigawatt, a gigawatt statewide. So that must be quite a bit of scaling up, but at this time the Commission wants to make sure that these loads are actually there when called upon. So the DRAM is being delayed for possibly half a year until we get the results back from how is the performance occurred.

I'm sorry. I'm getting still an echo.

CHAIRMAN WEISENMILLER: No, it’s good. It's certainly much better than it was. Thank you.

MS. CHUNG: Okay.

CHAIRMAN WEISENMILLER: There was also a note that actually SoCal Gas who had also been pushing for gas demand response, so that's certainly something that I think only one other utility in the country has tried. And so the first season, the first winter for Aliso Canyon, I think it was like December they got approval from the PUC, so not much happened.

This year it had more time, but again not a lot has happened and they just filed the advice letter for the next one. It's Arthur and his folks were going to take a stab at it.

MS. CHUNG: Right. But I'm familiar with for Aliso Canyon, is actually in front of the meter which is not demand response. But the solicitation, I believe is going out next month.

CHAIRMAN WEISENMILLER: Great. Thank you.

MS. RAITT: Okay.

So I think that what's his name, did he ever --

CHAIRMAN WEISENMILLER: Wait, I think Arthur wants to make a comment.

MS. RAITT: I'm sorry, go ahead.

MR. HAUBENSTOCK: Just one quick note on the DRAM. The industry is really very concerned about this delay. We have been gearing up quite a bit to participate in the DRAM. And many companies have been attracted to California as a result. It's not clear exactly what the problem is. And it's important that there's clear communications for the industry, so that we don't lose the momentum that we started to build in trying to have demand response industry really participate in the ISO markets.

MS. CHUNG: So it’s going to be really very interesting what will be coming in late July workshop.

CHAIRMAN WEISENMILLER: Yeah. I think again life's setting priorities and certainly it would be good to get this moved up on the priority list. And certainly some of the questions, which we've answered like for the new providers or new customers aren't that hard. Certainly the reliability is the important question, as is the price.

MS. CHUNG: I do agree with that.

CHAIRMAN WEISENMILLER: Great. But again certainly if you have comments on how we can step up the demand response program, or if Edison or PG&E, we certainly would like to see this in the written comments obviously or San Diego, obviously.

MS. RAITT: Okay. So we’ll move on. So thank you to our speakers and I'll say to go ahead and take seats in the audience, and ask our next panel to come up to the front tables. And we'll have places for you there. So we’ll just take a moment to transition here.

(Pause to set up the next panel.)

MS. RAITT: Okay. So we'll be talking about flexible resources and the first speaker is Grant McDaniel from Wellhead Power Solutions.

MR. MCDANIEL: Good afternoon it's a pleasure to be here. I want to take the opportunity to talk about the hybrid technology that Wellhead developed with General Electric and have installed into two Southern California Edison plants last year.

So our goal of hybridization is really to maximize the flexibility of the existing gas fired generation that we have. And the benefits of doing that, and what we accomplished were number one to eliminate the Pmin. We do have a true zero Pmin unit and this allowed us to have full use of the entire operating range between the Pmin and the Pmax without any operating constraints.

We have also eliminated any kind of minimum run time. For example, you can run for five seconds or you can run for five hours. We've eliminated the minimum down time, so that if you come back down to zero and you change your mind two minutes later or two hours later, you can come right back up. There are absolutely no limitations. So it's truly very, very flexible generation.

It has automated energy management, both of the state of charge of the battery. It doesn't put a burden on the grid, as well as the starting and the stopping of the CT behind it.

It can provide high-speed accurate regulation. But primarily it's going to be providing GHG-free spinning reserves. And this does count toward that headroom that Neil was talking about meeting earlier. And it also goes towards freeing up or gaining flexibility out of the existing assets that are running right now and having to be reserved. And we'll kind of take a look at that in a minute.

It can provide the automated responses for primary frequency response and voltage support, with or without fuel. Again, the technology's now been deployed at two sites: Center and Grapeland sites in Southern California. And as we'll see in some of the numbers here at the very end, exactly what the use case is now is that they are providing spinning reserves and voltage support without gas.

And when they are needed, they provide regulation, rather than just peak energy.

So overall, our design in terms of the control itself is that the unit can take either the CAISO dispatch in or it can take a local dispatch from Southern California Edison in this case, or it can be automatic depending on if it sees a problem on the grid in terms of voltage or frequency, it's just going to respond on its own. And when it responds on its own it will not use the gas unless the gas is absolutely necessary to use.

The hardware control system that was developed is a true high performance blended output. The battery and the gas turbine will both contribute as necessary to give you one very precise output to the grid.

This is just an example of a nominal instructed energy ramp on the gas turbine, or on the EGT, which by the way stands for electric gas turbine hybrid. This would be, just as you can see starting at zero. If you instructed it to go to 50 megawatts it would ramp up to 50 megawatts. The ramp down would look similar. You can see underlying the blue line that you have both the battery and the gas turbine are contributing to this ramp up through the range.

This is a variable ramping machine though. So this entire ramp can actually be moved from a ten-minute ramp to a five-minute ramp if that's so desired. And of course the primary frequency response would be quicker.

So how does this benefit us in the market? Again, the current dispatch we do have to hold back on megawatts that are currently producing energy. The CCGTs right now, 34 percent of the time we're on spinning reserve in 2017. If you were to hold back 34 percent on a 500 megawatt plant just by simple, simple example here it'd be 170 megawatts that's being reserved for contingencies, cannot be used for flexi-ramp, cannot be used towards ramping. It's reserved. And the CTs, simple cycles today, if we do need flexi-ramp they're going online to Pmin, which can be anywhere from 25 to 50 percent of their load. And then there are dispatch for energy as you might need them.

When you do the re-dispatch of a hybrid in the dispatch stack, and it's providing the GHG-free spinning reserve, that means 100 percent of my combined cycles can now be there for actual energy. That means they're running at a more efficient point, which means GHG savings. It means load payment savings.

By our calculations out through 2030 the average would be about 38,000 metric tons per year per EGT in the system. The overall system -- don't want to mess this up here.

The CCGTs, because you freed them up, that additional megawatts can is now flexible, where it wasn't flexible before because I was reserving it. It can now go towards inter-hour flexibility. It can go to meeting the ramp, so your entire Pmin of the system is actually reduced and your peak energy can now be met with more efficient resources.

And as a side benefit, because the site-specific emissions are going to be reduced that does have advantages for disadvantaged communities.

So Edison, in terms of what has been their experience has been really exactly what we talked about. Their use case has been changed from one of being a peaking plant to being a reliability center. They had over 90 percent of the hours that were in spinning reserve. That means they were displacing something else that was burning fuel. A small amount of time they were in regulation, overall GHG reductions at site specific was about 60 percent. That also goes towards local criteria pollutants, same amount. And they're estimating a 45 percent reduction in water usage at the site, which their estimates right now is about the savings of a million gallons a year. Thank you.

CHAIRMAN WEISENMILLER: So a couple questions. One is what's the optimal, in terms of the ratio of storage versus this. You know, do you have a sense of what the optimal sizing criteria are?

MR. MCDANIEL: Yeah, so in all cases you want to optimize on a minimum size storage that's going to give you the maximum benefits. And I think as a rule of thumb, 20 percent.

CHAIRMAN WEISENMILLER: 20 percent.

MR. MCDANIEL: And I think that would also apply to other technologies that we're beginning to look at in colluding combined cycle plant, of the operating range.

CHAIRMAN WEISENMILLER: Okay. That was good. This is certainly interesting. As you know we have -- as far as questions it's going to be in terms of how does this actually happen in terms of obviously a lot of our gas fleet at this point is -- the owners have put them up for sale and no one's bought them. The price has been too low, so how do you get someone to invest in the gas fleet to build the storage in?

MR. MCDANIEL: I think it's a good question, but I think when you look at the benefits that that actually brings to the grid in terms of integrating renewables, and in terms of reducing overall cost, that the value is there for the investment to actually occur. Where, if you leave the conventional assets alone, their value is continuing to degrade even though the system needs them for reliability.

CHAIRMAN WEISENMILLER: Thanks.

MS. RAITT: Okay, great.

So next I'll move to Douglas Black and Jason MacDonald from Lawrence Berkeley National Laboratory.

MR. BLACK: Okay. Well, we're going to really going to challenge the time limit here, but we'll try and just hit the high points and leave plenty of time for questions.

The Los Angeles Air Force Base converted its gas fleet of vehicles to a mix of battery electric vehicles and plug-in hybrid electric vehicles. The primary mission and objective was to demonstrate that electric vehicles could meet the mobility mission.

Our mission there was to develop a control and optimization system to minimize the charging costs and maximize ancillary services, regulation, revenue participation. All of the vehicles and charging stations were bi-directional charging capable.

This is a pretty busy box diagram of the system. I just really want to highlight that we had a control system server on the site at the base that communicated. That did forecasting and optimization and charge control of the vehicles to minimize charging costs. It forecasts day ahead bids that were transferred to our scheduling coordinator at Southern California Edison. Those were then transmitted to the top of the California ISO. Awards were then transmitted back through SCE to us and ISO had control during market participation, direct control with the AGC signal being sent directly to our control system that then was disaggregated to discharge each individual vehicle to meet that aggregated target.

We had a bit of a more manual bidding and awarding procedure than was optimal, really. There were -- we transmitted our bids to SCE through a standard spreadsheet day ahead. At 8:00 a.m. they submitted bids to ISO. At 10:00 a.m. awards were then transmitted back to our resource, where we had set up an automated processing of an email with a spreadsheet form of awards to then set up for our charging and participation the next day.

We bid -- well we were certified by CAISO for a 500 kilowatt resource, both in up and down regulation, this was first generation hardware we had issues with. There were hardware issues that was the responsibility of another part of the project. We were really forced to bid at the minimum 100 kilowatts of up and down. But we did, at that minimum as many hours as we could to gain as much experience and information with ISO, and our own resourcing collect as much. What we're really looking for is how would a resource like this be dispatched? What kind of AGC award would we get? How would we respond to it? So we want to get as much experience with that as possible.

Later in the project when the resource became a little more dependable, reliable, we did rely more on our optimization where we varied our bids based on the varying load that we had that comes with electric vehicles.

Here's just one example of two hours of our participation, which the blue line is the AGC signal sent from ISO. The red is how our aggregated fleet of vehicles responded. The overlay went very well, the resource responded rapidly to the four-second signal.

One of the big questions we get of course is how much revenue was generated? How much money did you make in the market? As the hardware problems did limit us, they were far lower than we had hoped to be as far as in size of what we could provide in the market. And given all of the -- sort of given the CAISO resource fees and scheduling coordinating fees, we were only in the black for one month.

Oh my goodness. Okay. I'm going to speed up.

But when those fees are taken are removed and just looking at a per vehicle basis, we had anywhere from $25 to $70 per vehicle, per month, if we don't include the fees. And I'll skip over those fees and --

MR. MACDONALD: Yeah, so I'll jump in and talk a little bit about market challenges, market participation challenges and at a high level anyway.

The most important thing and why it was

difficult with these resources, is they change in size all day long as vehicles unplug and re-plug in. And so with this resource changing in size there isn't mechanisms for battery resources and things like that in the market. And CAISO struck in the way that they operate, to manage those changing parameters throughout the day without going into outage modes and it's not really what it's meant for.

So that created a lot of issues for us. One particular thing that I'll point out is that CAISO did help us in one of these particular things with managing state of charge in the day ahead market and I can go into more in detail later if necessary.

Another issue was with our telemetry. When we sent telemetry that represented the actual connected resource we had, even if that was greater than what we had been awarded in the day ahead market, the ISO would immediately dispatch us to that greater telemetry value. And so we had to manually or take and instead report in telemetry, the lesser of our award or what was actually available currently, because we are choosing our awards based on what we can do throughout the whole day knowing our schedule.

Another thing that was important that was alluded to, is that we couldn't participate in hour-ahead bidding. And that was because we didn't have an automated path to get our bidding to SCN. It was just far too cumbersome for them to take that kind of information, and which made us much more conservative with our bidding.

MR. BLACK: And just one last point I want to make. We have a follow-on project, a CEC EPIC project. Because one of the big remaining questions while we tried to look at it in this study, and another group from MIT that was involved through another funding source, tried to look at the impact of providing bi-directional V2G services with vehicle batteries. What is the impact on those vehicle batteries?

We tried to tease it out as much as we could from the data we had. We didn't see anything that indicated there was a greater degradation, but we also don't have enough variation across the batteries as far as the amount of V2G that was provided that we can tease out any type of relationship.

So with this follow-on project, we are going to start with new batteries in the LEAFs, take the old batteries in a second-life application, in some temperature controlled chambers on the site to support the PV that's also at the site. And do a controlled study with the AGC signals that we collected and challenge batteries at different degrees to look for a relationship between providing V2G service and battery degradation, because that's a big remaining question in using these vehicles in this application.

CHAIRMAN WEISENMILLER: Well, thanks. Obviously this is primary research. And one of the things I wanted to focus on is at this point at least have you reached agreement with the ISO? My impression with the ISO, was that one point was that what you thought you were providing and what they thought, there was a mismatch there. At this point, are you at least synced up between with the ISO and what you're delivering in terms of services?

MR. BLACK: Yes, and we had a period where we weren't syncing up. It took some work with them to get synced up that way. But with the performance scores we received from them, we met the accuracy requirements other than one situation with where there was a mismatch in the minimum amount we said we could provide, which excluded all but three of our 15-minute periods in a month. And that lead to a decertification.

But no we -- their telemetry should show our response met what they were sending.

CHAIRMAN WEISENMILLER: Okay. No, that's good.

MR. BLACK: Yeah.

CHAIRMAN WEISENMILLER: And again, I think before this I was going to say is a problem, I think we've all seen the one vehicle at PJM, so it's good to see more of a fleet. And the question was again the odds that they were to call David and I and say, "Okay, we need your car now," that it's plugged in is pretty small.

But you know with the fleet presumably of vehicles, either that of a collection of charging infrastructure you at least have a shot of the VGI providing some value to the grid.

MR. BLACK: Yes. The fleet is definitely the way to start. And we thought with the military fleet too, with a reservation system that there would be a great response to providing -- we would know when every vehicle would be checked out and when it would be used. Not so much.

Even in a military fleet that is very regimented, it's still a challenge to predict when a vehicle will be used and when it will be available. But, still fleets are the better way to go. But I wouldn't exclude public either. We have another project using public vehicles too. That it could work.

CHAIRMAN WEISENMILLER: Great. Okay. Thanks.

MS. RAITT: Okay. So next is Shana Patadia from ChargePoint.

MS. PATADIA: Okay. All right, so I'm Shana Patadia. I'm from ChargePoint and so what we worked on was a Residential Controlled Charging Pilot as well as some 15118 Integration effort, so I'll try to go through this quickly and get to all of that.

So one of the things we did was a Residential Load Management Pilot Project. And in this project we provided 30 ChargePoint home stations to residential customers in San Diego Gas and Electric territory. And the way that this pilot worked was we basically took one month where we collected data about each of these drivers' behaviors in terms of how much they charged each evening and what time they plugged in, and what time they departed each morning.

And then we had a second phase where we basically controlled these drivers charge overnight. And the idea here, the premise of the pilot was that we wanted to charge these EVs overnight, in a way that was as responsive to the SDG&E price signal as we possibly could be, but without either touching the driver's experience whatsoever or by slightly benefiting them by saving them some money, and so really trying to create this win-win situation.

The way that we did this was after that first month phase in the second two months where we sent them a controlled charging schedule, each of the drivers would have downloaded the ChargePoint app. And when they plugged in their vehicle each evening, they would get an email or a text message on their phone. And the message, we tried to do all of the thinking for them. I think a previous speaker kind of made the comment that if you want demand response to work, you've got to make it simple. And that's how we approached this too. If we want people to really use the TOU price, we have to make it simple.

And so the message that they got was something like, "Your vehicle will have 40 miles of charge added to it by 7:00 a.m. tomorrow. If you would like override it for today, please click this button," so very, very simple messaging.

And then if they for some reason didn't opt out, they could later go in and opt out for that day. And again, the next day they'd get the same message and have the opportunity to make a decision again.

We saw a great response actually, so of the 1,005 sessions, charging sessions that were conducted during this period of our trial, about just over 50 percent of them people stayed in the charging schedule, so less than 50 percent opted out.

And if you look at the price per kWh, and obviously this is all related to the price signal we chose and we used a price signal from the SDG&E Power Your Drive Program, so it's an experimental rate. But that being said, if you look at the difference in the price cents per kWh without the charge scheduling the price was around 29 cents per kWh and then with the charge scheduling that was about 16 cents per kWh.

So that's a significant difference, especially when you consider that it meant nothing really to the driver. They benefited equally in terms of their driving capability in both situations.

And then, as I mentioned on the right of that slide, basically if we assume that the average home charger charges their vehicle 300 kWh per month, that can be an annual bill reduction of around $500. That can be significant. So yeah, so in the interest of trying it always think about creating a simple solution for the customer we really wanted to always create a low effort solution, but also one that would allow the driver to have high confidence.

And, you know, I spoke to a lot of the people that participated in our pilot. I also had a survey and we got some of their feedback. And what we learned is the drivers said -- so one of the questions I had asked them was if something like this became a permanent program, what would motivate you to participate? And one of the answers that we got often was, "I wish I could see the state of charge in my app. I wish understood the total miles of charge, not just the miles added. I wish I could just limit the vehicle to charging up to 80 percent SOC, so that I could use my regen braking," etc.

And I think that's a very interesting result, basically the idea that just providing the drivers with more information would increase their willingness to participate. And I think that that's probably a lesson that can significantly also be pulled away from the residential setting, but into the commercial setting or public charging like Doug was talking about.

And I know one of the pilots they worked on, they asked the drivers for more information.

And having that info makes the driver feel more comfortable that you're going to actually get done what they need.

Another portion of our project was getting simulation results from Lawrence Berkeley National Labs through their V2G Sim tool. And to summarize this slide since time is short, basically I think what we got out of the exercise was a) network chargers are absolutely essential, because whether there's TOU or DR or whatever we want these vehicles to respond to in the future, if we don't have those network chargers out there in homes, how will we ever be able to take advantage of that?

And secondly, you know, thoughtfully controlling this residential EV charging as shown in this slide would allow us to stagger the charge. So that if you have ten of your neighbors all buy EVs you're not overloading the transformer and suddenly need a distribution upgrade. You can defer that just by strategically charging those and staggering the charge.

And then finally, what we also did through this project was we integrated 15118 on a ChargePoint home station and we tested that against a Daimler Smart ED vehicle. And we were able to look at the various capabilities as much as we could with that vehicle. So we tested pass-through pricing as well as a calculated charging schedule back and forth. And basically we were able to successfully demonstrate the use of 15118. And that's it.

CHAIRMAN WEISENMILLER: I guess ChargePoint has a variety of chargers, home chargers, workplace chargers etcetera. I'm just trying to figure out, in terms of have you tried experiments on the workplace side?

I think you've probably heard President Picker say that his charger at home is used only by him. It's only used when his car is there and charging at night is not hitting or the duck curve.

So trying to get people to focus more on workplace charging and trying to focus on basically providing this sort of shifting, but trying to shift into the duck as opposed to within some points in the night.

MS. PATADIA: Yes, so I can respond to that with two things. One is the project that we're doing. Alameda County uses the LBNL team is doing, uses ChargePoint chargers. And one of the things they're doing there is asking people when they park, "How much charge do you need? How long are you going to be parked here?" And then adjusting the charging accordingly, so they're basically distributing that charge along with the charge at their other stations there in trying to keep their demand charges down, but also manage the overall load.

Another response I'd have is that we at ChargePoint have been looking at programs like the Excess Supply Pilot, for example, which directly addresses the duck curve. What I will say though is some of those programs can be challenging, because very similar to some of the reasons Doug pointed out, the load of these EVs is very small and it's unpredictable. And some of these products haven't necessarily been catered to the EV load.

CHAIRMAN WEISENMILLER: Yeah, I mean obviously Google or Facebook, a lot of the Silicon Valley companies have very large numbers of workplace chargers. Are you connected with them?

MS. PATADIA: Yeah, and they are fully capable of using what we call power management, so basically keeping their power ceilings low. My understanding, and obviously I can't speak for any of those companies, but my understanding is that the economics haven't necessarily played out to make it worth it for them to bid into these various programs or participate. Just because there isn't sufficient earning for them to make or the minimum bid is too high or various other reasons.

CHAIRMAN WEISENMILLER: Okay. Thanks.

COMMISSIONER HOCHSCHILD: Just curious, how many chargers does ChargePoint have today?

MS. PATADIA: Oh, I wish I knew the number. I don't unfortunately.

CHAIRMAN WEISENMILLER: If you could submit it later for the record, that'd be great.

MS. PATADIA: Absolutely. Absolutely.

MS. RAITT: Okay, so thank you.

Next is Rohan Ma from Tesla.

MR. MA: Great, hi. My name is Rohan Ma. I manage the Energy Optimization Team at Tesla and what that means is we develop the dispatch algorithms for stationary storage under Tesla's direct control. That's everything from the consumer power wall product operating behind-the-meter to aggregations as well as utility scale storage that we control. That's what I'm going to talk about today, is our experience operationalizing the large Australia battery at the end of last year.

This is just a nice picture of the site. The site is called the Hornsdale Power Reserve. It's in South Australia. Neoen is our partner where the site is located.

And just some key stats on the project. It's a 100MW/129MWh battery. It's co-located with a 309MW wind farm. The resource is registered as two resources, because that market there doesn't have a storage resource ID. And so the discharge side is a generator and the charge side is a dynamic load. And it's registered for nine products in that market, so Energy Regulation Raise and Lower and then all the six other contingency products are similar to spin and non-spin operating reserves here in the U.S., just different variations of it.

So every time we bid we're bidding two resources across nine products.

Just some charts of how operations have gone. This is a day, a few weeks after we turned on when there was really volatile energy prices, doing what I think is most intuitive to people in terms of how energy storage should work when we charging at low prices and discharging at high prices.

On this day, the energy prices in Australia are uncapped or essentially uncapped, most similar to ERCOT in Texas. And so prices were actually up at $14,000 a MWh on this day when we were discharging. There is no capacity market in that market.

The other big application for the battery is to provide contingency support and so this was a day early on where the battery was responding to a frequency event on the grid. And so whenever the frequency in Australia goes outside the nominal range, in this case it was below 49.85 hertz the system autonomously responded. And so the x axis here is second and you can see the blue line is dipping below the bottom dotted line. That's as soon as the frequency dipped out of the nominal range, the battery immediately started to respond.

We could have responded with a more significant power injection, but we're actually limited and throttled back in terms of how quickly we respond, because of just the coordination issues on the grid. And so we have a proportional response, as frequency continues to dip lower and lower our power response increases and then comes back down as frequency starts to approach the nominal level.

So in terms of how we operationalize this battery in the market, this is just a flow chart of the basic steps in terms of who's involved. There's obviously the physical Tesla battery. We're then operating it in the cloud, we call it Autobidder. That's in an Amazon web service. That's generating all the bids and all the optimization and forecasting.

We're passing those bids through machine-to-machine APIs to our partner's control room, the operations room in South Australia, which is manned 24/7 365. Those bids are basically passing straight through and going directly into the market operator who's clearing the market and then communicating market enablement through the transmission operator directly to the battery.

And so just in terms of how we've implemented this, I think for a lot of people in the room that are familiar with this, but because energy is an energy-limited resource, the way we have to think about bidding and participating is very different than renewable resources or conventional thermal resources. Because we are buying and selling electricity, so our marginal costs or what our bids are based on is really a function of an opportunity cost. And that is constantly changing, particularly with a shorter duration battery, because it's a function of our forecast or short-term expectation of market conditions.

And so because of that, we are actually bidding every five minutes into this market. So the rough kind of timing is about 30 seconds into the current 5-minute dispatch interval. We are collecting information from the market that has just been updated. That is feeding a set of forecasting models and algorithms that we used to update our expectation of what's going to happen and that comes into an optimization or a decision-making model.

The output of that is a bid, which is then validated and passed through the market. And so we're bidding about 60 seconds ahead of the dispatch interval clearing, which is very different than CAISO and other U.S. markets that we are actually bidding. You know, we're getting awards or we're bidding 30 seconds before an actual dispatch interval is set. And that's because their market runs much more quickly than the U.S. markets in terms of the way they solve it.

And so about five, ten seconds into the next dispatch interval we're getting our awards for that interval and then we're collecting information and already thinking about the next dispatch interval.

COMMISSIONER MCALLISTER: So is this basically an automated process?

MR. MA: Yeah.

COMMISSIONER MCALLISTER: So you basically say here's our envelope of what we want to achieve and you just sort of automate that in?

MR. MA: Yeah. It’s all algorithmically driven is the way to think of it. Obviously, we're supervising it and we've developed it, but it's essentially a machine-learning model seeking information and generating bids.

COMMISSIONER MCALLISTER: But on the dispatch side as well?

MR. MA: Well, so it’s going into the market operator, basically clearing the market against all resources and communicating the enabled award directly to the battery.

COMMISSIONER MCALLISTER: Right, okay.

MR. MA: So we're using, yeah we're using algorithmic driven strategies to generate our bids, but ultimately it's being cleared just like any other resource.

COMMISSIONER MCALLISTER: But at also a

very short interval?

MR. MA: Yeah, every five minutes. Yeah.

COMMISSIONER MCALLISTER: Yeah, okay. Thanks.

MR. MA: And then yeah, I'll just to wrap up. I mean, this is just a visual of market activity. This isn't a metric of success or anything like that, just the sizes are a count of rebids or bidding activity in the market. And the two big ones are the battery load and generator size and this is just a way to show, I guess how much more active we've been in this market, than any other resource.

The next biggest circles are hydro, which is the most similar to energy storage. But we really have a bid at a much higher rate than any other resource, simply because of the nature of the challenge we're trying to solve operationally.

And then the last one is just a visualization of the number of the different unique combinations of awards that we had in the first month. And the two to call out are the two far right ones where the far right one is intervals where we cleared every single product simultaneously, so the battery is earning revenue across all nine products at the same time. So maybe it's got an energy award to charge, but it's providing flexibility up and down, both in contingency and regulation simultaneously.

And then maybe even the more interesting one is the one second from the right, which is all eight products without energy. So meaning we're providing all the ancillary services with no energy awarded in the market. And that's unlike any of the other conventional resources there, because they have to be in the market in energy in order to provide the flexibility off that base point.

So I think consistent with what people expect, but this is all real data and it's operating 24/7, 365 as of now. That's it.

COMMISSIONER HOCHSCHILD: Great. I know we had J.B. Straubel came and spoke here maybe six weeks ago and gave an overview. And said the project is over-performing from a financial perspective as well.

MR. MA: Yeah. Yeah, it's doing well. I can't speak about the specifics, but financially it is doing quite well.

COMMISSIONER HOCHSCHILD: And I understand it was built -- Elon Musk said it would be built in less than 100 days, it would be free. And you got the tests run.

MR. MA: Right, yeah.

COMMISSIONER HOCHSCHILD: Yeah, I mean I'm just curious looking ahead, I mean this is obviously a landmark project. The largest storage project in the world, but do you -- how rapid growth do you foresee? I mean, given these results and the implications for California, and I don't know what your California market looks like for future projects like this. But I mean, how rapidly do you see the storage market developing in California?

MR. MA: Yeah. I mean I think to a certain degree there's some degree of, I guess we're seeing this in Australia where now that we're in the market and folks are seeing what the technical capability of the resource is, it's making them rethink potentially some of the products that the market itself requires. And some of the standards associated with those products, that I think will change the market structure there.

I mean, here in CAISO there are some aspects of storage compensation that are better than Australia already. The U.S. generally, things like mileage payments for frequency regulation and things like that, that doesn't even exist in Australia yet.

At the end of the day, I think that the need needs to be there for the batteries to provide services. And that is fundamentally driven by renewable penetration.

I guess the only other aspect I would add is things like accuracy scores for frequency regulation are important. In terms of what we're seeing in Australia is that we are providing a service that is, even though it's the same product, it's fundamentally different than what the conventional thermal resources are providing in terms of quality. And this is something the market operators are starting to quantify and realize.

And to the extent that those types of rules could be improved here in terms of accuracy and things like that, it's going to help storage in terms of where we are today.

COMMISSIONER HOCHSCHILD: Yeah, a couple of more just quick questions?

MR. MA: Yeah.

COMMISSIONER HOCHSCHILD: What is roughly the roundtrip efficiency here? Lithium ion's your chemistry right, and is it you're 85, is it roughly around that?

MR. MA: Yeah, it's around that. Yeah.

COMMISSIONER HOCHSCHILD: Is that right, and have you looked at other chemistries? Vanadium, or any of the other?

MR. MA: Tesla surely has. You know, we're not right now. I mean, we're pretty wed to that technology right now in terms of our whole supply chain and manufacturing being oriented around that. But yeah, I mean Tesla's constantly reevaluating those types of technologies and are really looking at what's needed to get to the fully sustainable grid in terms of 10 years down the line, 20 years down the line. And those are all conversations, but I mean in this case we've had to do something in 100 days. It was pretty clear what technology we were going to use.

COMMISSIONER HOCHSCHILD: Yeah. I mean I'll just say in closing I am a big supporter of regionalization as a vision for the state. And I think that's a sentiment pretty widely shared by my colleagues. But that is in the hands of the Legislature that doesn't get it over the finish line. I mean, we've got to solve this challenge somehow and I think the advantage of storage is it goes both ways, right? You can produce power and you can absorb power and it does provide that resource.

Well, thanks for your presentation. It was terrific.

CHAIRMAN WEISENMILLER: Yeah, thanks.

MS. RAITT: Okay. So that's the last of our speakers. We can go on.

CHAIRMAN WEISENMILLER: So let's go to public comment, anyone with a blue card? Please.

(Off mic colloquy.)

MS. RAITT: So did you have one of these cards that you wanted to speak?

CHAIRMAN WEISENMILLER: Yeah. I was going to say we have only one blue card, certainly come on up. Steve?

And anyone else who wants to speak, please give a blue card.

MR. UHLER: Good afternoon and Happy Solstice in about 12 hours. Thank you, Commissioners, for my chance to speak here.

I'd like you to think about a couple of things. They were talking about renewables going to baseload. I think they need to go to a load following, then also modeling has a lot of limitations. I'd like to see if you can go to material requirements planning, what used to be called MRP or is MRP.

Because a lot of the questions and a lot of what was shown in this meeting, you could be clicking on a screen and having all those answers all the way down to the solar panel that was used and how somebody ended up using those dumb inverters to feed the transmission system, because of their capabilities that they have but used in a different situation.

So I'd hope you'd think about for one identifying all of the power plants, all of the components in your appliance database, all of them in your solar panels, with a number system that's very friendly to high-speed data processing, because you could get all of these answers. You wouldn't end up with a high, medium and low.

You could say, "What if we go this way? What if we do all this hybrid stuff? How is it made up and what will happen to Tesla's bidding system when there's 100 people doing Tesla's bidding type systems? You could actually see that happen, because you build a physical product structure. I see that missing and I'm hoping that the Energy Commission will put together that stuff.

I've already sent a data structure to the Commission for power content. If you can define what goes into power content down to little tiny utilities, you should be able to run that all the way up. Divide and conquer and handle all of the data that's required to move this faster. I want that Tesla stuff here. I want that hybrid gas generator. I want that now.

We should already be further along. People talk about a duck chart, does anybody remember a zero energy home curve? I'll put that in my written comments where you'll see there's a lot of -- we're reinventing things that we talked about years ago.

I think about a guy named Daryl Chapin. He's co-inventor of the solar panel. If he would be talking about this like duck chart, "What do you mean? 1952 when I made this thing Bell Labs hadn't look at that kind of stuff."

We need to move forward faster, so please think about redundant, man flight, belt-and-suspender approach of having four or five or six forecasting resource planning systems that play against each other and compete. Instead of right now it's resolve and pathways? Those have got to be tedious to keep going and they're slow, so think about that. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

Valerie?

MS. WINN: Good afternoon, Chair Weisenmiller and Commissioners. Chair Weisenmiller, you had asked Ms. Burns a question about the number of renewables contracts in PG&E's portfolio. So I wanted to let you know that we have about 275 non-utility owned gen RPS contracts. And that represents about 7,000 megawatts in total. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

So any other public comment, either in the room or on the line?

MS. RAITT: So on WebEx, if you want to raise your hand to let our WebEx Coordinator know that you want to comment?

(No audible response.)

MS. RAITT: Okay. So there's nobody, but we're going to take a moment to open up some phone lines. So folks who are on the phone line and wanted to make a comment will have an opportunity.

Okay. So nobody on the phone to make comments.

CHAIRMAN WEISENMILLER: I wanted to thank everyone for their participation today. We're looking forward to the written comments, which are due?

MS. RAITT: July 5th.

CHAIRMAN WEISENMILLER: And again I'd like to see more progress next year than we've had so far on I think we've done a pretty good job about identifying issues. But in terms of really trying to move forward on implementing solutions and mitigation, that seems to be dragging.

COMMISSIONER HOCHSCHILD: No comment, let me just thank the staff, Kevin in particular for a great day and a really, really fruitful discussion.

COMMISSIONER MCALLISTER: I wasn't here for most of the day, but I'm looking forward to reading the -- particularly that first afternoon panel that I missed, so I hope to see comments on that as well. Thanks.

CHAIRMAN WEISENMILLER: Great, so the meeting's adjourned.

(The workshop was adjourned at 3:47 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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Juliana Link

Juliana Link
CER-830

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MARTHA L. NELSON, CERT**367

December 4, 2018