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COMMITTEE HEARING

BEFORE THE

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT

COMMISSION OF THE STATE OF CALIFORNIA

In the matter of,	)
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Integrated Energy Policy	)
Report (IEPR)	)

IEPR COMMISSIONER WORKSHOP ON THE

2015 CALIFORNIA ENERGY DEMAND

PRELIMINARY ELECTRICITY FORECAST

CALIFORNIA ENERGY COMMISSION

FIRST FLOOR, ART ROSENFELD HEARING ROOM

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JULY 7, 2015

10:05 A.M.

Reported By:
Kent Odell

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California Public Utilities Commission

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P R O C E E D I N G S

JULY 7, 2015 10:05 A.M.

CHAIR WEISENMILLER: Commissioner McAllister is joining a little late, but told me just to get this thing going.

So, Heather, let's do it.

MS. RAITT: Great. Good morning. Welcome to today's IEPR Commissioner Workshop on the California Energy Demand 2016-2026 Preliminary Electricity Forecast. I'm Heather Raitt, the Manager for the IEPR.

A few housekeeping items. Restrooms are in the atrium, the snack room is on the second floor.

If there's an emergency and we need to evacuate the building, please follow staff to Roosevelt Park, which is across the street, diagonal to the building.

Today's workshop is being broadcast through our WebEx conferencing systems and parties should be aware that you're being recorded. We will post an audio recording in a few days and a written transcript in about a month.

Today, we'll break for an hour lunch at about noon.

And at the end of the day there will be an opportunity for public comments. And we're asking parties to limit comments to three minutes.

For those in the room who would like to make comments, please fill out a blue card and give it to me. When it's your turn to speak, please come to the center podium and speak into the microphone.

For WebEx participants, you can use the chat function to tell our WebEx coordinator that you'd like to make a comment during the public comment period. And we'll either relay your comment or open the line at the appropriate time.

And finally, we'll take comments from phone-in-only participants.

If you haven't, please sign in at the entrance to the workshop. And if you got here early, we have since added some of the presentations. So, if you didn't get them all, you might want to go out and get the other presentations.

And comments are welcome. They're due on July 21st. And the notice provides the information for how to submit comments.

And with that, I'll turn it over to the Chair.

CHAIR WEISENMILLER: Thank you, everyone, for being here today. One of the more important things we do as part of the IEPR is to adopt the Demand Forecast. And so appreciate -- this is our preliminary draft, so we appreciate everyone's comments.

CPUC COMMISSIONER FLORES: Mike Florio, from the PUC. It's a pleasure to be here. If it's a little cooler than last week, I'll take credit for it. And looking forward to an interesting day. Thank you.

MS. RAITT: Okay, our first speaker is Chris Kavalec, on the Statewide Forecast Results and Methods.

MR. KAVALEC: Good morning. I'm Chris Kavalec, from the Energy Assessments Division. And I will be starting out the presentations today looking at some statewide results for our California Energy Demand 2016-2026 Preliminary Electricity Forecast, or CED-2015 for short.

I will also be talking about some of our key inputs and assumptions that we make for the forecast. We typically, also present a natural gas forecast when we do our forecast workshop. However, for this IEPR cycle, we've decided that we would combine our end-user natural gas forecast with the natural gas forecast for generation, and so on, that's done in our Supply Office. So, we presented our end-user natural gas forecast earlier this year.

So, today's only about electricity. A high level summary of this forecast relative to previous forecasts, we have a new geographic scheme that I'll be talking about in a minute.

Overall, at a statewide level, electricity consumption is down comparing our new CED-2015 mid-case with the mid-case from our last adopted forecast, California Energy Demand Update, or CEDU-2014.

There's a much greater decrease in electricity sales and peak demand because of higher self-generation, more specifically PV projections that affect sales in peak.

Oh, I should probably mention the -- round out the schedule today, before I go any further. So, after my presentation we'll have Asish Gautam talking about our self-generation forecast.

We will also have a presentation on our rate scenarios. Lynn Marshall, who developed these scenarios is on vacation this week, so Malachi Weng-Gutierrez will be filling in for that presentation.

And then, in the afternoon we'll be doing planning area forecasts for the major planning areas, along with SMUD. And Malachi Weng-Gutierrez and Cary Garcia will be making those presentations.

And after each of those presentations, the utilities will be allowed, encouraged to come up and make comments or a short presentation.

Back to the presentation. This is what we call a baseline forecast only, meaning it doesn't include additional achievable energy efficiency.

For the revised forecast, we will be including AAEE savings, both for the IOUs, brought to us by the CPUC’s Energy Efficiency Potential Study, and for the first time we will be attempting to do AAEE savings for the POUs, using whatever data we can gather. So, that will be part of the revised forecast.

Okay, statewide results. Before I get to that, just a brief review of how we forecast, how we develop our demand forecast. Starting at the top, we have our key inputs and assumptions, econ and demo drivers, historic consumption data, energy efficiency and other demand modifiers.

And then, in the middle of the diagram there we have the traditional models that we use for forecasting, residential, commercial, transportation, communications and utilities, or TCU and street lighting, agriculture and water pumping, and industrial.

And our residential and commercial models are full end-use models, meaning they’re bottoms-up models.

Our industrial model is sort of a semi-econometric, semi-end use models. And then the other models are either econometric or trend analysis.

Off to the right there, we also have our predictive model for self-generation, for the residential and commercial sectors. And then on the left we get forecasts for electric and natural gas vehicles from our Transportation Unit.

So these results go to the summary model, where we adjust for weather, aggregate, calibrate to actual historic consumption.

Then we provide our peak model. These consumption numbers at the end-use level and load shapes are applied. And from that, we get an annual forecast for peak demand.

We also have, for each of the sectors, a single equation econometric model, which we use as sort of a reality check compared to the end-use results. And we also use these econometric models to make adjustments to the main forecast. For example, for climate change, which I'll talk about in a minute.

As usual, three demand cases. A high demand case characterized by higher economic and demographic growth, more aggressive climate change scenario, high case for electric vehicles, lower electricity rates, and less self-generation. In other words, we rig it so that we get highest plausible demand, given our inputs.

And then the low demand case is basically the opposite, except in the case of climate change where we don't include any climate change impacts. And then our mid-demand case has assumptions that lie between the high and the low cases.

Looking first at statewide electricity consumption, you see our three cases there, high, low and mid. And the difference between the low and the high, by the end of the forecast period, is around 20,000 gigawatt hours.

And then the mid-case from our previous forecast in red there, from CEDU-2014.

I should mention that we were not able to process the 2014 consumption data for this preliminary forecast because we had some stragglers in terms of turning in the fourth quarter of 2014 data. But that will be remedied for the revised forecast.

CHAIR WEISENMILLER: Do you want to name any names on the stragglers?

MR. KAVALEC: No comment on that one.

You'll see the two mid-cases are pretty close. And the difference, really, comes at the beginning of the forecast period because we have a rate increase from 2013 to 2014, that was not in our previous forecast, and this pushes down consumption in our new mid-case below the old mid-case at the beginning of the forecast. And it stays below it through the end, through 2025, where it's around 1,000 gigawatt hours below.

Turning to sales, however, there is much more of a change because, as I mentioned, our higher PV forecast. By 2025, we're about 13,000 gigawatt hours lower than we were in the mid-case, comparing the two mid-cases. So, we're dropping in our mid-case, in terms of sales at statewide level, by a little bit less than 5 percent in 2025.

And more self-generation/PV, also has a significant influence on peak demand. Again, the new mid-case, significantly below the old mid-case by around 2,000 megawatts, by 2025.

The difference here, in relative terms, is not as high compared to sales because we made it a downward adjustment to our peak factors, the factors that we use to convert PV energy to peak impacts. And Asish will talk a little bit more about that later.

Statewide consumption per capita basically mirrors the results from consumption. Although, comparing the two mid-cases, they're a little bit farther apart because we have a slightly higher population in our new mid-case, which brings down the per capita.

Overall, we're, of course, proud of our relatively flat consumption per capita in California. And we show that continuing. Although, later in the forecast period it begins to go upwards slightly because of more electric vehicles and because of a projected increase in residential plug loads.

Okay, our new geographic scheme. The goal here was to develop our planning areas so they match more closely to balancing authority areas, and within Cal-ISO to the transmission access charger or TAC areas.

We also increased the number of climate zones to 20, from 16. And within CAISO, these forecasting zones are meant to approximate Cal-ISO's transmission planning zones, the level at which they do their transportation planning analysis.

And we will continue to discuss and make gradual improvements in our refinement of our forecast results because there is obviously need for that, with distributed resource planning, and the need to have information on locational EE and other demand modifier impacts.

So, but that's where we are now, and we will continue the discussion and determine a level, the next level of geographic granularity to shoot for, beginning with the next forecast.

This is what our old planning area scheme looked like. The highlighted -- the eight planning areas. The planning areas highlighted in green are where we have made revisions. Those have changed compared to our previous forecasts.

So, first off, what was our old PG&E planning area now becomes the PG&E Transmission Access Charge Area, in CAISO.

To do that, we basically had to pull out some of the entities that were in our old planning area, but are not part of CAISO. Like Turlock Irrigation District, Modesto Irrigation District, a few others. So, those are pulled out and what's left is our new planning area, corresponding to the PG&E TAC area.

For Edison, it was a little easier. It was just a matter of adding in Pasadena, which before was its own planning area.

And those entities that we pulled out in Northern California, from our old PG&E planning area, those were combined with SMUD top give us a new planning area, referred to as Northern California Non-CAISO, NCNC.

Our other planning areas, LADWP and Burbank-Glendale, and so on, are the same as before. And we add another planning area, Valley Electric because, even though it's fairly small, it is considered its own transmission access charge area, so it becomes a new planning area.

And here's a listing of our climate zones for our revised planning areas. We have six climate zones. Again, these are meant, at least in the CAISO territory, to correspond to transmission planning zones for CAISO.

For PG&E, we have six climate zones, compared to the five we had before.

For Edison, we have five, compared to four in our previous forecasts.

Northern California Non-CAISO, there you see is number four, now consists of three forecast zones or climate zones, one defined as the SMUD Service Territory, then the Turlock Irrigation District Balancing Authority. And then number 15 there, the rest of the Balancing Authority of Northern California Control Area, aside from SMUD, is our third.

And you see there Valley Electric, which is both its own planning area and its own climate zone.

And this is my feeble attempt to develop a map to show these new climate zones. What I did here was to attempt to show the climate zones that are now part of the California ISO, which are most of the climate zones.

For the revised forecast, we'll get our GIS people involved and develop more professional maps. But this is what I have now.

So, Northern California, PG&E Planning Area, climate zones 1 through 6. Southern California Edison, climate zones 7 through 11. San Diego, down there at the bottom, number 12. And over there in the middle, on the Nevada border, we have dinky, little Valley Electric as climate zone 20.

Okay, some of our key inputs and assumptions, beginning with economic and demographic assumptions. Our high demand case, as it has been in recent forecasts, is defined as Global Insight's optimistic scenario. Of all the scenarios we look at, this one typically is the highest in terms of economic and demographic growth.

For our mid-demand case, we have the Moody's baseline scenario. And for our low demand case, Moody's lower scenario, they call their lower long-term growth case. And included in that was DOF population since that, among the three here, Global Insight, Moody's and DOF, DOF projected the slowest population growth. So, that was part of the low demand case.

Overall, there's little difference compared to the econ demo drivers that we used for CED-2014. We do have in our demand forms, posted with our report, on our website, a list of the key economic drivers, their values, and the sources from which they came.

So, I'm only going to talk about the one exception here, where there has been a significant change in our assumptions, and that's the number of households.

In the past, we tend to be fairly conservative when it comes to projecting number of persons per household. We typically have assumed that it is going to remain flat, because that's what recent history tells us.

The reason this is important is that for a given population, the smaller the number of persons per household you assume, that means the higher number of households in all else equal a higher residential forecast.

So, that has been our practice in the past. And that you see the number of household assumptions for our previous forecast in red there.

Now this time, because we're coming out of a recession, we have an aging population, and we have most economists projecting, including our economic vendors, projecting a decline in the number of households, we've decided to go with the flow this time and assume declining persons per household. Which increases our projections for the number of households.

So as you see here, all three of our new scenarios are higher than our mid-case from the last time. And this has an impact, particularly in Northern California, where the rate of growth of number of households is highest, PG&E and SMUD.

On to self-generation, we will see a presentation on this self-generation and PV a little bit later this morning.

We sort of divide it into two types, small-scale adoptions in the commercial and residential sector for technologies like PV, and solar hot water, and so on, and our traditional, large industrial power plants. And today we get data from that, from our QFER, Quarterly Fuel and Energy Report.

For the residential and commercial small-scale adoptions, we have predictive models that use costs and benefits to develop a payback period for each technology. And that payback period is transferred to an adoption curve to give us a prediction for number of adoptions in each year.

For this preliminary, for CED-2015 preliminary, we refined our modeling in the residential sector using actual load shapes. And, more importantly, we modeling the adoptions using tiered rates, instead of just assuming one average rate. And this made a big -- had a significant impact, as we'll see in a minute.

So, going forward for the revised forecast, it looks like that we may need to refine this assumption because we are likely to see flatter tiers than what we currently have.

Okay, statewide photovoltaic energy. You'll see the big difference between our old mid-case there, in red, and our three new demand cases.

So, by 2025, comparing the two mid-cases, we're about 12,000 gigawatt hours higher in terms of electricity generation from PV. And as I mentioned earlier, most of this is coming from our -- this increase is coming on the residential side because of the changes we made to the residential model.

COMMISSIONER MC ALLISTER: Hey, Chris, can I jump in a little bit there?

MR. KAVALEC: Sure.

COMMISSIONER MC ALLISTER: So, it seems like there are a few things going on. I mean, this is obviously a very important influence on net demand at this point, and sales.

MR. KAVALEC: Uh-hum.

COMMISSIONER MC ALLISTER: And I think there are some uncertainties there that -- this is an awful smooth curve and, obviously, you know, it's a model so you kind of expect that.

But there are some discontinuities coming.

Maybe you've got one of them happening at 2016, when the ITC, the Federal ITC expires. So, it looks like you've got a little sort of lower percentage growth there for a little while.

MR. KAVALEC: Uh-hum.

COMMISSIONER MC ALLISTER: But I think also, so this flatter-tiered period, I won't speak for the PUC, but my understanding is this flatter-tiered period is a temporary period and then after that there will be some time of use, and that's all -- I mean, the details, you know, TBD, obviously, but that seems like it's relatively a good bet.

CHAIR WEISENMILLER: But I mean, this reflects the current tiers increasing so --

COMMISSIONER MC ALLISTER: Yeah, exactly, so that's kind of --

CHAIR WEISENMILLER: -- there has to be some adjustment for that, too.

COMMISSIONER MC ALLISTER: So, yeah, exactly. So, you're sort of -- I guess, you know, maybe it's a little magic-wandy, but we do know something about what the rate structures are going to look like going forward. So, maybe the revisions of the model need to take multiple inflection points into account, kind of. So, I'll defer to Commissioner Florio here, on some of the details, but you probably -- I'm not sure how much you can say about this but --

CPUC COMMISSIONER FLORES: Yeah. Well, the last Friday's decision contemplates residential TOU in 2019. I'm not sure -- I mean, we don't really know what those rates are going to look like. The general statement is moderate differentials by time period, at least in the default rate, but looking at having a menu of options. So, it could be more complex than what we've been dealing with, historically.

COMMISSIONER MC ALLISTER: Yeah. So, maybe the -- you know, I don't know all the details of what your inputs to your model and what your behavioral conceptions are but, you know.

CHAIR WEISENMILLER: Yeah, again, one of the things to keep into account is that the jump between the red line and the other lines is going from an average retail rate to a rate structure.

COMMISSIONER MC ALLISTER: Yeah.

CHAIR WEISENMILLER: And so, now that we have a flatter rate structure, presumably that will pivot things down a little bit, also.

COMMISSIONER MC ALLISTER: Exactly.

CHAIR WEISENMILLER: So, there's a lot going on in this area.

COMMISSIONER MC ALLISTER: Oh, absolutely. That's kind of my point here is that maybe, as you refine the model, a predictive model, you can see how well some of these new, anticipated scenarios map onto your inputs and kind of figure out how you might be able to reflect that.

MR. KAVALEC: Yeah, so I see our job, at least for this particular model, is attempting to incorporate both a flatter rate structure and the beginning of much more widespread time-of-use rates. So, this is a work in progress.

But this is where we are now and, obviously, we're going to make some changes for the revised forecast.

COMMISSIONER MC ALLISTER: Yeah. And maybe that actually is, also, maybe more so a peak, a non-coincident peak or a peak discussion, as well. Okay, thanks.

MR. KAVALEC: Okay, speaking of peak impacts, here's what they look like for our latest forecast. Again, also, these are showing actual peak impacts, as opposed to nameplate capacity.

By 2026, we're a little bit above 5,000 megawatts in terms of peak impact. And that corresponds to around 13,000 megawatts in nameplate capacity.

Again, much higher than our previous mid-demand case. Although the difference, in relative terms, is not as high as I alluded to before because we're using a lower peak factor to convert from energy to peak. So, the peak difference, in relative terms, is not as high compared to the energy difference.

COMMISSIONER MC ALLISTER: And so, are you taking into account the specific, you know, utility demand shapes in that? Is that an aggregate from the individual utility levels, or the load areas, or whatever? Or is this kind of a statewide -- is the factor kind of a statewide factor?

MR. KAVALEC: It differs by utility.

COMMISSIONER MC ALLISTER: Okay.

MR. KAVALEC: And I'll let Asish speak to that when he makes his presentation.

COMMISSIONER MC ALLISTER: Okay, great.

MR. GAUTAM: Okay, so the adjustments we made to the peak factor was based on historical utility system peaks for several years onto our production, PV production profiles. And so, they do differ by the different planning areas, as Chris had alluded to.

And there's an important thing here, and I'll talk a little bit later in my presentation that there's expectation of a shift to a later evening peak. And we haven't really accounted for that. We want to talk to the utilities a little bit more on that topic before we make any changes.

COMMISSIONER MC ALLISTER: But this, the megawatts there, are those -- is that a system peak reduction or is that a sum of individual utility peak reductions?

MR. GAUTAM: That's a sum of individual utility peak productions.

COMMISSIONER MC ALLISTER: Okay, thanks very much.

MR. KAVALEC: Okay, while our Transportation Unit attempts to develop an electric vehicle, a new electric vehicle forecast, a new set of scenarios we can all be happy with, we have resurrected our electric light duty vehicle forecast from 2013, and updated it based on the most recent historical sales numbers for electric vehicles.

These scenarios, from 2013, consisted of a low-demand case, which was meant to correspond to the most likely compliant scenario from the ARB in terms of the number and types of vehicles that will be produced and sold to meet the ZEV mandate.

We also had a high case, where we increased the number of plug-in hybrid vehicles using our model predictions.

And then we had a mid-case, which was in between the high -- exactly in between the high and the low cases.

So, for our preliminary forecast this is what we have. We will, hopefully, have another set of updated scenarios for the revised forecast.

Now, this is a statewide forecast, so we have to distribute this to our planning areas and climate zones. And we did this through a regression analysis, where electric vehicle ownership at the county level was specified as a function of whether the county was rural or urban, and per capita income. A fairly simple formulation that we can improve on over time.

And because we made an adjustment for recent EV sales, which reduced the mid and the high cases, for those scenarios we have a slightly lower forecast for EV consumption, compared to what we had in 2013 and in our 2014 CEDU update.

So, here are the scenarios, starting from our current estimate in 2014, of electric light duty vehicle consumption of around 300 gigawatt hours statewide.

In the high case, we reach around 9,000 gigawatt hours by the end of the forecast period.

And then, in the mid-case, almost 7,000 gigawatt hours.

The purple one there, the low case, as I mentioned, that is corresponding to ARB’s most likely compliance scenario from 2013, for the ZEV Mandate.

There have been some tweaks made to the ZEV Mandate since 2013. For example, the smallest automakers no longer have to produce battery-electric vehicles for sale.

So, we will -- assuming that in our revised forecast we have a scenario that’s based on a most likely compliance case, that will change because ARB’s most likely compliance case will have changed.

Comparing the two mid-cases, as I mentioned, we’re a little bit below. And that’s because, basically because of the adjustment we made in the most recent historical years to account for actual sales.

Underlying these consumption projections we have our projected stock. And this is a total of battery-electric vehicles and plug-in hybrid vehicles.

So, in the high case we’re getting over 4 million vehicles on the road by the end of the forecast period. And in our most likely compliance case, around 1 and a half million.

In terms of the composition, in the low demand case, we have about one-third of the vehicles as pure electric or battery-electric, and the rest plug-in hybrids.

And in the high demand case, which as I mentioned we added a lot more plug-in hybrids, we have around 12 percent of the vehicles as battery electric and the rest as plug-in hybrid.

In terms of efficiency, and here I'm talking about what we have traditionally referred to as committed efficiency. Efficiency from initiatives that have been finalized, and approved, and funded. As opposed to additional achievable energy efficiency.

So, in terms of committee efficiency, there's not a lot to talk about because the new standards were not adopted in time to include in this preliminary forecast. Although, we will have some new standards to look at for the revised forecast.

And, as I mentioned, we don't have AAEE savings, yet, for the forecast. The CPUC's potential study is not quite finished and we have to work with the CPUC and Navigant to develop scenarios for these numbers, and we'll do that in the summer and the fall. And as I mentioned, also put together AAEE numbers for the POUs.

So, there are some new savings, however, to incorporate for committed efficiency. We have 2015 IOU programs that were not in our CEDU-2014. And we have another year of publicly-owned utility programs for 2014.

Also, since our last forecast we have the results of the latest Evaluation, Measurement and Verification Study from the CPUC, for the 2010 to 2012 period. And those -- that study basically showed that actual realized savings, overall, were not as high as had been expected or reported.

So, we had to make an adjustment downward to our efficiency numbers for 2010 through 2012 because of these results. And, in fact, we made an adjustment for the whole period of 2010 through 2015. Even though the study period didn't apply to those latest years, it's the best information we have in terms of realized versus reported savings.

We did the same thing, we also applied this to the publicly-owned utilities' expected or report savings for the 2010 to 2014 period. Again, the study was for the IOUs, but this is the best information we have.

Okay, so this is what the adjustment looks like. What this graph is showing is accumulated efficiency program savings, in this case for the IOUs, starting in 2010. So, the red line there is what we have in our previous forecast in terms of savings starting from 2010 through 2014.

And then you'll notice after 2014 it starts to decline. That's because we have no new programs and our measured savings are decaying away over the rest of the forecast period.

When we make the adjustment to account for the EM&V results, we move down to the dark blue line. The way we did this adjustment was CPUC had data down to the measure level, which we converted to end uses. So, each end use was treated differently because it had a different realization rate.

But this is, the dark blue summarizes the impact of all of these end use adjustments for efficiency program savings.

And then, we have to add in new savings from 2015 and that brings us to the green line. So, the amount of program savings we have starting in 2010, for this preliminary forecast, is defined by the dark blue line until we get to 2015, and then it becomes the green line.

The same thing here for the publicly-owned utilities, again the similar adjustment made based on the latest EM&V study. However, in this case the last year is 2014. We don't have reporting savings, yet, for 2015, for the POUs.

Again, starting in the red, that's what we had in our previous forecast. Going down to the dark blue, making the adjustments, then adding in the 2014 new program savings. So, we have the dark blue up through 2013 and then the green from 2014 on.

Electricity rate cases, this is probably not a good title as it confuses -- it might be confused with actual rate cases. So, it's demand cases for electricity rate scenarios is what this should be called.

So, for this forecast we developed our own electricity rate scenarios, with the new staff model, which consists of a set of equations developed to -- or formulated to develop revenue requirements and allocate these revenue requirements to rate classes, and then calculate average rates. And Malachi will talk a little bit more about this new model in his presentation.

And then, we developed high, mid and low cases by varying the expected demand, load demand, carbon prices, and natural gas prices.

And overall, in our mid-case, for all the different planning areas, this model gave us a rate increase of between 20 and 27 percent in this 13-year period, in our mid-demand case.

And we will be doing -- this is the first run of this model. We will be doing another forecast for our revised -- another set of scenarios for our revised forecast and we will be seeking input from the CPUC, as well as the utilities before we develop a new set of rate scenarios.

As in recent or other recent forecasts, we attempt to incorporate climate change through temperature scenarios developed for us by Scripps Oceanography. They run these global climate change models and then they downscale the results of these models to 50-square-mile grids in California.

So what we do is we match our weather stations, that we use in our forecast, to the appropriate 50-square-mile grid. And from that we get projections of increases in maximum temperatures and, also, changes in heating and cooling degree days.

These changes, first off for consumption, changes in heating -- changes in heating and cooling degree days are converted to changes in consumption through our residential and commercial econometric models.

Our peak forecast is adjusted using these projected increases in maximum temperatures, translated to a load impact through our peak econometric model. We assumed climate changes impacts only in the high case and the mid-case, not in the low case.

First, looking at the impacts on consumption, the high demand case there in -- oh, by the way, what we asked Scripps to do was provide us, among all the different scenarios that they've run, a case, a scenario that's roughly in the middle in terms of temperature increase, and then one that's more at the high end, for our high demand case.

So, for our high demand case, in green there, we have an extra 1,200 gigawatt hours in electricity consumption because of higher temperatures, more cooling degree days.

Looking at the mid-case, however, you'll see that there is not much of an impact. And that's because in the scenario that they gave us for the mid-case, there was a very high decrease in the number of heating degree days. So, even though cooling is a much more important end use for electricity than heating, the decrease in heating degree days was so high that it almost offset the impact from more cooling degree days. So, we end up with a paltry 60 gigawatt hours of impact by the end of the forecast period.

So, moving forward, I'm not sure if this mid-case is anomalous or not. But going forward, what I'd like to do, and I've talked to Guido Franco, our climate change expert about this, is to develop a distribution for these scenarios. And from that distribution, use a mean and a standard deviation, or some other statistic to develop our scenario. So that we are -- our results don't depend so much on a case that may or may not be anomalous.

On the peak side, much more what you would expect, over 1,000 megawatt load impact by the end of the forecast period in the high case. And a little bit over 600 megawatts in the mid-case.

And at a statewide level, on average, this corresponds to, in the mid-case, an increase in maximum temperatures of about three-quarters of a degree. And in the high demand case, about one and a quarter degree increase overall, looking at a State average.

Demand response, we have traditionally included non-event demand response in our forecasts. Meaning, programs like time-of-use rates and permanent load shifting.

More recently, we have begun to include some event-based programs on the demand side. And the reasoning is that for resource planning there are some event-based demand response programs that can't be integrated into the CAISO system. And, therefore, it makes more sense, from a resource planning point of view, to include these programs on the demand side.

So far, we include two types of programs, event-based programs. critical peak pricing and peak time rebates. However, when this discussion all shakes out at the CPUC in terms of what constitutes demand side, or load-modifying demand response, and what's supply side, we may have some additional programs to include.

But this is what we have now. And the total impact, incremental impact on load by the end of the forecast period, for the three IOUs is around 260 megawatts. As I mentioned, future forecasts might include more impacts, more programs.

We are also involved in an analysis of much more widespread use of TOU rates, with the CPUC and the California ISO. So, we have hired a consultant, who is doing an analysis for various scenarios for TOU participation and rate differentials. And we will hopefully have some results to talk about towards the end of this month.

COMMISSIONER MC ALLISTER: Hey Chris, on the load modifying, where's your data coming from? Is it mostly the evaluations of the PUC's programs?

MR. KAVALEC: That's right, the IOU evaluations.

COMMISSIONER MC ALLISTER: Is there any POU activity there?

MR. KAVALEC: There is a little bit. And we haven't looked at it, yet, but we do have some information from the demand forms that they provide us which --

COMMISSIONER MC ALLISTER: Okay, great.

MR. KAVALEC: -- we can hopefully incorporate into the revised forecast.

COMMISSIONER MC ALLISTER: Do we get any input from, you know, private companies, or third parties that do demand response work, sort of aggregators and things like that?

MR. KAVALEC: No, we do not.

COMMISSIONER MC ALLISTER: That just sort of -- maybe they could provide some insight on the future there, too.

MR. KAVALEC: That is a --

COMMISSIONER MC ALLISTER: I mean, it's a little anecdotal, but it's a little market intel that would be nice, too. Yeah, I saw Melanie earlier, that's kind of why I'm thinking of it. They're right there, she's hiding.

But it just strikes me that there's a lot of kind of market savvy out there, not just from Melanie's company but, you know, there's a few of them out there that maybe could help you look into the crystal ball a little more clearly.

MR. KAVALEC: Yeah, and hopefully these folks would also be involved in the CPUC's potential study for demand response, which is getting underway.

COMMISSIONER MC ALLISTER: Yeah, great.

MR. KAVALEC: Because of the uncertainties involved in this early stage for TOUs, the results of this analysis will feed into the IEPR. However, they will not be part of our forecast, at least for this forecast. Maybe for 2017 on they will be, but not for this forecast.

As just sort of an exercise here, given all the attention to the drought, I looked at the potential impacts of a continuing drought on our agricultural and water pumping sector.

There's two types of water pumping, as you probably know, surface water pumping from reservoirs, and then groundwater pumping, with groundwater pumping being more energy intensive. So, when you have less rainfall, all else equal, you're going to have more groundwater pumping and, therefore, more energy being used or electricity being used. And that's what this shows here.

So, the red line shows the gigawatt hours of consumption in the ag and water pumping sector statewide, assuming a continued drought. That is, for this purpose I took an average of the last three years, which is our drought period.

Compared to the case where we have -- we go back to a 30-year average for rainfall. By the end of the forecast period, we get around a 400-gigawatt hour difference or impact from the drought, around two and a half percent. So, not major, but this could be part of a larger analysis, given the interest in the so-called water/energy nexus here.

Next steps, of course we will incorporate comments and we will have, as you will see this afternoon, plenty to talk about with the utilities and other stakeholders.

And we will -- luckily, we have the DAWG, Demand Analysis Working Group, mechanism to do this. So, we'll be having some DAWG meetings to resolve the issues that we have in our respective forecasts.

We'll be, as I mentioned, updating our historical consumption. We will also be, in October, getting summer loads for California ISO and developing a 2015 weather-normalized peak as a new starting point for our forecast.

Updating is always our economic and demographic assumptions. And rates, again, we want to get the utilities and the CPUC involved in this discussion.

Additional achievable energy efficiency for both POUs and IOUs will be incorporated and we have new standards, as I mentioned, to look at.

The revised EV and PEV forecast probably didn't need a question mark. I'm pretty sure they will be revised to some degree.

Also, we have a contractor working on estimating, giving us estimates of additional electrification, besides electric vehicles, from the truck stops, and ports, and trains, and so on. So that will be -- that additional electrification will be part of our revised forecast. It's not in the preliminary.

And as usual, we have troubleshooting issues in our models that we need to look at for the revised forecast. In this case, I'll just point out the one that seems the most important. There seems to be some issue in terms of projecting plug loads in our residential model. It seems to be a little high. It's based on a series of equations for each planning area and it looks like it's, for unexplained reasons, increasing by a higher percentage than we think is reasonable. So, that's something we need to look at for a revised forecast.

And this has an impact on some of the planning areas, particularly SMUD, where we think the residential forecast may be a little high. So, this is something we'll be addressing for the revised forecast.

And with that, I'll ask for comments and questions.

CPUC COMMISSIONER FLORES: It's clear you're working with PUC staff on a number of these. Are there any areas where you need greater input than you've been getting, that we could help out?

MR. KAVALEC: Can I get back to you on that?

CPUC COMMISSIONER FLORES: Sure.

MR. KAVALEC: I'd like to think that over a little bit.

CHAIR WEISENMILLER: Certainly, would encourage you, and your staff and our staff, to talk about the rate numbers, both in terms of how the rate design is changing and what that means on the PEV numbers. But also, in terms of rate increases just to make sure we're not -- yeah, I'm sure there may be other things. But t hose are the two that jump to the top of my mind.

COMMISSIONER MC ALLISTER: I wanted to just mention, you know, on the AAEE front, the fact that there is quite a bit of collaboration going on between the agencies on unpacking the impacts of codes and standards, and trying to figure out what we think is actually happening in terms of real adoption based on code updates. Versus, you know, what's unrealized savings that needs a program to go out there and capture it. And so, I think that's an ongoing question that the forecasting team here, you know, you and your colleagues ought to be involved in to see really what analytical resources we might need to go try to get to figure that out. Because I think we're pretty macro right now and we really need to dig into that a little more. A quite a bit more, actually.

MR. KAVALEC: Yeah, and I want to say I appreciate the CPUC for allowing the time and effort of Navigant to provide us these AAEE numbers. It's a lot of work and they are very cooperative.

Okay, thank you. And we will now hear about our photovoltaic and self-generation forecast.

MR. GAUTAM: Good morning, everyone. My name is Asish Gautam and I'll be going over the solar generation forecast.

First, I'm going to talk a little bit about the data sources we use to track DG activity in the State, and then I'll go over some of the changes we made for this forecast. And then I'll present the statewide results. The individual planning areas will be given later in the afternoon. And then, I'll go over our next steps and take any questions or comments you may have.

Regarding data sources, we want to kind of highlight the difference between using rebate program data versus interconnection data for tracking the installed capacity of DG, mainly of PV, and how we use that to translate -- how we translate installed capacity to energy and peak impacts.

In prior IEPR demand forecasts, we mainly relied on utility rebate program data because it was easier to access. They typically contain a lot more information than I think what you would get out of the interconnection data. And these data sets were typically updated fairly frequently, so they served as a useful proxy for interconnection data. And I've listed some of the different DG programs that we had tracked.

Initially, what came up in the 2013 IEPR, we were trying to reconcile our differences with the utilities regarding the PV capacity. And we discovered there was a lot more PV being installed than what the rebate program data was showing.

And the reasons for that, you know, we were still experiencing cost reductions in PV systems, they had new types of financing and leasing arrangements that made solar much more affordable, and not so dependent on rebates.

And since we used rebate program data to track

DG activity, this is going to leave a hole in our DG assessment. And so, we came up with two options for remedying this data deficiency.

The first option was to use the IEPR's data collection regulation to request PV interconnection data directly to the utilities. This allowed us to get the updated historical data for 2012 to 2014, for us to use in this 2015 IEPR.

We have a longer-term effort to kind of look at our existing data collection regulations and to try to see what updates we need to do to collect this data on a regular basis. That effort is still ongoing.

And I have a table here to kind of show you how -- to show the difference between the interconnection data and the rebate program data. So, this is focusing just on the three IOUs' PV capacity additions for 2012 and 2013. The column labeled "utility" is straight from the utilities' interconnection filings to us. And the column labeled "CEC" is our estimate of PV additions based on publicly available data sources.

And you can see by 2013, the rebate program data is not really doing a good job of tracking interconnection data. We would have been off nearly 40 percent for PG&E, about 12 percent for Edison, and over 50 percent in the case for San Diego.

So, this data issue is a pretty serious thing for us and I think the PUC has also recognized that. They have a proceeding ongoing to post utility interconnection data online. I think that system's supposed to go online later this fall. So, we're hoping to maybe use that later on, in time for the revised forecast.

Some other changes that we've worked on for this preliminary forecast. In prior IEPR forecasts we've relied on an in-house PV production profile, provided to us by staff from our Efficiency Division.

The PUC has done a study of a portion of the CSI program, about a year ago, and they've provided some updated PV production profiles that we are now using.

Chris had talked a little bit earlier about changes we made to our PV peak factors. These are factors we use to the install capacity to estimate the peak reduction from PV system coincident with the utility peak.

In the prior IEPR, the utilities have kind of commented that our peak estimates tended to be on the high side. And so, what we did was we overlaid historical system peaks for a couple of years and tried to figure out how the PV systems -- what kind of reduction can we expect that would be coincident with the utility peak?

And, generally, we found the utilities have a valid point regarding our factors being a little bit on the high side. And so, we've adjusted our factors downwards, on average about a 20 percent reduction.

And the peak factors become even more important as you go out in the ten-year forecast. If you expect a shift toward the later evening peak, so that's going to reduce the PV peak impacts even further.

We're hoping to discuss this issue a little bit further with the utilities and do some revisions to our peak factors for the revised forecast.

We've also updated our PV cost estimates for the forecast period. We're relying on the PUC's NEM public tool for that data.

Chris had mentioned about the updates we've done to how we forecast residential PV. This is mainly focused on the IOUs. The reason for undertaking this change had to do with the changes called for in the rate design and the NEM compensation structure for under AB 327.

And in prior IEPRs, our forecasts for residential PV was based on using average sector rates, and we didn't really factor in net metering benefits because most of our input data were on an annual basis.

And so, we've requested, in addition to the PV interconnection data, load research data from the utilities to help us, for the first time, account for net metering benefits. And we're using retail rates for the first time, for the IOUs.

I'm sure everybody understands that there was a decision last week on some major changes to how residential retail rates may look like in the future. And there's also a proceeding to relook at how NEM compensation may work in the future.

These are changes we haven't really factored into our forecast, but we hope to do that in time for the revised forecast.

COMMISSIONER MC ALLISTER: Asish, I want to just ask a question. First, I want to really endorse that effort because I think the customer response to the rate incentive is really a key question. So, that will be really interesting going forward.

I wanted to ask about the transition away from the CSI database to other resources, largely at the PUC. I guess, so the cost data that was in the CSI database wasn't actually all that reliable. It was a little bit inflated and it didn't really reflect real costs. And I think it sort of -- you could use it for trending, but not really much else.

What’s the new tool that you’re using for costs and kind of where does it come from?

MR. GAUTAM: Oh, so the PUC, as part of their evaluation of net metering, has developed a NEM tool to allow users to figure out what different NEM compensation structures will look like on their end. As part of that effort, the PUC has also updated or developed new PV installed cost projections.

COMMISSIONER MC ALLISTER: Oh, gotcha.

MR. GAUTAM: I think the --

COMMISSIONER MC ALLISTER: So, a retail, like installed retail cost kind of thing?

MR. GAUTAM: Yes, that’s what I believe, yeah.

COMMISSIONER MC ALLISTER: Okay, great. And is that -- do you know, Mike, is that going to be an ongoing commitment to keep that up or to track the marketplace?

CPUC COMMISSIONER FLORES: Certainly try to.

COMMISSIONER MC ALLISTER: Yeah.

CPUC COMMISSIONER FLORES: I don’t know how much access we’ll have to information as we move away from the rebate structure, but it’s certainly something we want to try to keep.

COMMISSIONER MC ALLISTER: Yeah, and if we can collaborate or help in any way, I think that would be great. Because, really, the CSI database was just a gold mine to help businesses evolve and get it right for the customer. So, as we're moving towards more dependence on interconnection data and other ways to intuit what's going on in the marketplace, it's really important to keep that as a high priority, I think. And that will help you guys do a better forecast.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: Yeah, I guess another thing I was going to ask was when Severin did his paper, recently, on PV, he was basically distinguishing between tax benefits, rate design, and now.

And so, I guess going forward we should be working with the PUC staff to have some scenarios on them. I assume, as a bookend of the industry preference, it stays exactly as it is and the utility preference if it goes away. And then, presumably, there's some more likely scenarios that we could try to frame.

CPUC COMMISSIONER FLORES: Yeah, our target is still the end of the year for a decision on the future of NEM. I think we'll get party proposals later this month, give them some time to take into account the rate design changes. But, you know, that will be a big focus for the rest of this year.

You know, I think December is probably optimistic for a decision, so it may not be in time for this forecast but, certainly, the next round.

COMMISSIONER MC ALLISTER: Great.

CHAIR WEISENMILLER: I think on all these things that the update next year is going to really capture more things which are in progress this year.

COMMISSIONER MC ALLISTER: I mean, as we all know, there's so much hand wringing going on out there, in the self-gen industry, not just solar, but self-gen broadly, about kind of the confluence of events at the end of 2016, you know, roughly with the ITC, et cetera, and the rate reform, and NEM.

So, hopefully, that's not going to be the cliff that folks fear. And I think that's part of the goal here is to make it relatively continuous over time. So, yeah, definitely I would concur to work with the PUC staff on figuring out what the possibilities are there.

MR. GAUTAM: Yeah. So, the changes we've made, we think is a step in the right direction. But there are just so many moving pieces, as the Commissioners have noted. And as time goes on, we definitely will be looking at updating our data.

There was a mention of going to time-of-use rates, so that's something we're definitely interested in. And that's just something we have to handle later on.

COMMISSIONER MC ALLISTER: Asish, one final question. So, also, during the CSI there was some sampling of systems that were -- that had monitoring on them. You know, the whole monitoring regime was kind of developed for the kilowatt-based incentive. But even some of the smaller systems had monitors on them. That the utilities, certainly, and the PUC had access to, and some of that I think was made public.

In any case, the performance evaluations or monitoring of systems going forward, is that system still in place as far as you know? Is there data coming in, load-shape data, production data from some sample of PV systems, net metered PV systems coming in?

MR. GAUTAM: I think the systems that went through the performance-based incentive are still reporting. But I think that's going to transition out because, as the CSI is kind of sunsetting, there's not that many projects, I think, that are still subject to reporting their generation.

COMMISSIONER MC ALLISTER: Kind of like as soon as they don't have to report they --

MR. GAUTAM: Yeah, I think they're only required for like five years.

COMMISSIONER MC ALLISTER: Yeah.

MR. GAUTAM: We may be seeing an end to that. I should probably defer to PUC staff on that.

COMMISSIONER MC ALLISTER: You know, I don’t know how critical it is because I think we -- they’re relatively well-characterized. But they do degrade and kind of I think there is a long-term policy, important question there about the long-term performance of those systems, still. Also, again, it’s relevant for the forecast.

MR. GAUTAM: Yeah. So, other updates, focusing on non-PV technologies. This is mainly the Self-Generation Incentive Program. They also publish their interview reports. The 2013 report was released around May of this year and we have some timing issues. We’re not able to incorporate their findings into the preliminary forecast, but we hope to address that in time for the revised forecast.

In that report, we were hoping to see some more discussion on storage, but it’s kind of like the contractor for that report felt it was a little too early to look at storage, impacts from SCHIP. So, that’s another data issue or gap that we have.

Like with the prior IEPRs, we have updated electric and gas rates that we will use. We’re still using average sector rates for the POUs. And for the IOUs, again, we've gone to using actual retail rates, but we escalate those rates based on the price forecast supplied to us by the Supply Office.

Again, we have updated housing stock and commercial floor space data.

Just a quick overview of our forecasting approach. Our approach is a cost, benefit of cost effectiveness framework, using the other agencies. The metric we're choosing to use here is the payback period. So, basically, we take the system costs for the different technologies, those savings and any kind of policy drivers, like incentives, and factor that into the payback calculation.

That becomes an input to an adoption curve, which gives us the penetration rate. And, you know, this is the kind of the prototype S curve that's used to forecast adoption of technologies over time.

We've received some comments from utilities about moving away from some of these payback approaches and that we're interested in learning a little bit more on this. Hopefully, we'll have some upcoming DAWG sessions on these forecasting approaches for DG. But for now, this is kind of what we have.

The first result here, I want to go over, is the statewide non-PV self-gen impact share. As Chris had mentioned, the bulk of -- so, this data is really the large combined hidden powers cogen applications that report the data directly to us.

In 2013, our base year, the reported data makes up a little over 90 percent of the energy impact here. And then, the other 7 percent is what we estimate for the Solar Generation Incentive Program.

So, it’s hard to tell here, but we do have three scenarios. But, unfortunately, the scenarios are very close to one another. The reason being there are offsetting effects based on how the assumption’s embedded in the scenarios.

For example, the high demand case has a lower growth in electricity rates, which kind of dampens interest in investing in DG. But then you also have a lower price for your cogen of natural gas.

And then, also in the high demand case we have more economic activity, so there’s more opportunity for onsite generation.

In the low demand case, you have higher electricity growth, so there’s more of an incentive to invest in DG cogen. But then, you’re natural gas prices for cogen units are assumed to be higher, so that kind of dampens the effect there.

And then, we have lower economic activity, so less, slightly less in relative terms for DG, and the net result is the three scenarios are very close to one another. Compared to the last forecast, it's very similar, but just about one percent higher.

One thing I wanted to point out here, the onsite usage, as reported to us, tend to be centered in the large industrial or mining sectors. And so, we don't really create a forecast for that. We hold their output constant over time.

When you look at historic data that's -- their onsite usage tends to be fairly flat, and so the growth you see there is coming from the commercial sector.

Another uncertainty here is that the bulk of these large, industrial cogen projects also export a fair amount of their generation to the grid. And quite a few of them, of these generators, will have contracts that may be expiring over the forecast period. And it's not clear if they will continue to be generating, or shut down, or what the situation will be there.

And so, our colleagues in the Supply Office are taking a look at this issue for us, and we hope to incorporate their findings in time for the revised forecast.

Next is the statewide, non-PV, self-gen peak effects. Similar to energy, the three scenarios are very close to one another and just slightly above the 2013 forecast. Roughly about 100 megawatts higher, compared to 2013.

Let's see, here we have the statewide PV, self-gen impacts. Here, the three scenarios are easier to distinguish from one another. The reason being the rate effects, the rates -- the growth in rates have a more noticeable impact among the scenarios.

So, in the low demand case, where the rates are assumed to grow higher, they have more PV, the low demand has lower escalation of rates, so they have a little bit less PV.

The three scenarios are substantially higher than the mid-case from the last forecast. Again, the growth is mainly led in the residential sector. I think by 2026, about 70 percent of the impact is in the residential sector.

The nonresidential PV grows between 15 and 20 percent. So, there's a little bit of growth in kind of the commercial side, but not as much as the residential.

We want to, again, note that we have to assume, at least for this preliminary forecast, that the existing rates in the NEM retail compensation will still be in place over the ten-year forecast. But again, last week, there was a vote on some major changes to how IOU residential rates may look like. And we're hoping to incorporate that into our revised forecast.

By 2026, PV accounts for nearly 9 to 11 percent of consumption. We have a flattening, a slower growth after 2016. That reflects the expiration of a tax credit for the residential sector and a step down of 30 percent of the cost to 10 percent of the system cost for the nonresidential sector.

One other thing I wanted to note is that even though the three scenarios are substantially above the 2013 forecast, there's a reason to believe that at least the near-term forecast for all three scenarios may be a little bit on the conservative side.

The reason for that is when we look at the progress, or the forecast results, we don't show the IOUs meeting their NEM cap until the 2018-2020 time frame. This is the cap the utilities have to offer net metering benefits for their customers. It's set at 5 percent of their non-coincident peak.

But following the NEM redesign proceeding and kind of looking at what the utility filings are showing in their progress towards meeting their NEM cap, there seems to be some expectation, at least in the case of PG&E and SDG&E, they may meet their NEM cap as early as next year. And maybe, by 2017, for Edison.

There's also -- when we talked to the utilities a little bit about our results, there were some questions about a rush to get projects interconnected to take advantage of the tax credit and to get grandfathered under the existing NEM compensation structure. We haven't really tried to account for that.

One other note is I think this is the first time that the PV self-gen impacts exceed the non-PV self-gen impacts in our forecast. So, that's a pretty big shift.

This is the non-coincident PV self-gen, the peak impacts. Again, a similar story to the energy side, all three scenarios are above the mid-case from the last forecast.

Touching back on the peak factors, if we were to assume that the peak were to be later in the evening, these curves would shift down. But that's something we want to talk with the utilities a little bit more, and in time for the revised forecast.

These are preliminary results. We hope to hear from you about our approach, the reasonableness of our results, and any concerns you may have regarding the treatment of retail rates, the NEM compensation structure.

And we did an optional scenario to take a look at how residential PV may change if we were to model the rate reform for the residential sector for the IOUs. So, the blue line here is assuming the current tiered rates stay in place, having the four tiers, and also giving the full retail credit for net exports.

The red line is taking the tier flattening schedule, from the April decision from the PUC. So, here we have a shift from four tiers, to three tiers, and then two tiers by 2018. And after 2018, we just hold the 2018 tiers and escalate it by the retail rate escalation from our price forecast.

And, you know, no surprise there, the adoption -- you get a lot less adoption here. There's a missed typo here. It says there's a 1,200-megawatt reduction. There's actually about 1,600 megawatts. So, I kind of apologize for that.

So, these rate assumptions have some very big impacts that we need to address for the revised forecast. But again, there's a lot of -- we've got a lot of moving pieces. Nothing's been finalized, but there's a lot of things that we do have to try to address as best as we can.

Just a list of our next steps. For the revised forecast, we want to update our historical data. We're still trying to go through the new rate reform proposal, approved last week. The net metering proceeding is still ongoing. We'll try to see what we can incorporate from that proceeding in time for the revised forecast.

Also, last week the utilities filed their distribution resource plans. We're still going through that to see where we can incorporate some of those plans into our forecast.

We did not have time to address storage in this preliminary forecast. We just ran out of time. But we're hoping to do something on storage for this revised forecast.

For the longer term, we have a project or we're trying to initiate a project to change how we do our long-term peak demand forecast to better account for the changes in load shapes from DG, energy efficiency, storage, and the electrification, and transportation sector.

We're looking at some contracts over here, and we are in the process of selecting a contractor. Hopefully, we'll have a team in a few weeks and have results in time for the 2017 IEPR.

And this concludes my presentation and I'll take any questions.

CHAIR WEISENMILLER: A couple of questions or comments. One is, just remind everyone that one of the things we're doing this year is moving from a focus on lining up the two agencies on energy efficiency to, also, preferred resources.

So, we really need to make sure that as we go through the methodology that that's being well-baked with the PUC staff.

And I think the other thing is we've talked about having -- as part of the DAWG, having a conversation on this with the utilities. Are you inviting some of the solar companies?

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: To, again, try to get their perspective, some sense of their marketing plans.

The one gap that we're probably not picking up, and you see this current arc in marketing of the solar companies to say, okay, we have a limited window for the tax credits. You know, if you're trying to go through, say, PUC approval process, you know, the RFP approval process, you're not going to get there. So, let's go bang on the door of an Apple, or Google, or Kaiser, or somebody and have something where there's a project somewhere. It's nowhere close to that, but somehow there's a link between them buying the -- or paying for that power and that being used to credit.

So, again, that's something, you know, you talk about how there's not a lot of additional CI. But I think if you really pick up some of that more virtual, you know, sales, you'll probably see a substantial growth in that, particularly between now and when the tax credits expire.

CPUC COMMISSIONER FLORES: Yeah, I think from what I've been able to learn, it sounds like those are mostly direct access transactions. And, you know, there's a bill in the Legislature that would allow another, I think it's 8,000 gigawatt hours, and that would all be renewable. So, I think we can see, expect somewhat more of those kinds of developments.

COMMISSIONER MC ALLISTER: Also, just I mean I totally agree with both of those comments and was sort of figure out a way to suggest that you get the solar companies into the conversation. I mean, you know, my experience is it's kind of hard to get them to share their business models.

But the additional point I would make is there is a pretty solid -- you know, you're looking at all the data about cost, and rates, and stuff. But I guess there's a pretty clear value proposition right now that the solar, that the residential solar, you know, which is the lion's share of the marketplace that you're looking at, that the residential solar companies are able to sell on. Right, which is, look, you've got to beat the tier three price, basically, right.

MR. GAUTAM: Right.

COMMISSIONER MC ALLISTER: And so, the thing is you can do a lifecycle cost assessment of the cost of generation, if your installed costs of PV are good. And you can match that up with different scenarios on the rate side. You know, you take away the ITC slice at the right moment, and everything.

And I think you're going to find that the lifecycle cost of solar, you know, well done, at a reasonable price is going to be below any reasonable scenario for even possibly tier one in the future. Right? And I'm not saying anything -- you know, this is all public kind of opinion.

But I think the fears of sort of the demise the solar, the retail solar industry, rooftop, are very premature. And so, but it would be really good for us to sort of hammer on that analysis, together with the PUC, and say, look, what's the lifecycle cost under a reasonable financing scenario? What's the competitive price that a solar company, doing rooftop, could offer? And how does that likely match up to the new rate regime possibilities?

And I think that would help, I think, give us --

maybe, you know, the slam dunk value proposition goes down a little bit, and those margins have to go down, but I think it's going to be competitive. And it would be really good to kind of have that analysis --

MR. GAUTAM: Okay.

COMMISSIONER MC ALLISTER: -- inform that conversation with the solar market.

MR. GAUTAM: Okay.

CPUC COMMISSIONER FLORES: Yeah, I think that's right that the no-brainer opportunities are going to disappear with the tier flattening, but there will be a broader opening to customers who it just didn't make sense for before, as the lower tiers increase.

COMMISSIONER MC ALLISTER: Totally. I mean, if you -- let's say, you know, 20 cents ends up being tier one or something, you know, 18 or 20 cents. The reasonable lifecycle cost for installed rooftop solar, you know, a 4, 5 kw system is substantially lower than that already, and it will probably only get more so. And so, and that's a part for the ITC. You know, it's right in there, in the teens. So, at least that's what I think. So, for what it's worth.

But it would be good to kind of go in with that, you know, put some boundaries on the conversation as you sort of engage with some of the solar companies. I mean, undoubtedly, we'll see some consolidation and the market will shift. But I think there's still going to be a very good value proposition.

MR. GAUTAM: Yeah.

COMMISSIONER MC ALLISTER: Great. Nice job, thanks.

MR. WENG-GUTIERREZ: Good morning, my name is Malachi Weng-Gutierrez. I work in the Demand Analysis Office. And I will be presenting on the Preliminary Retail Electricity Rate Projections. These were prepared by Lynn Marshall. And her contact information is here, if there are any questions afterwards. I'll try to answer any questions that you have during the presentation.

So these electricity rates were generated to cover the sectors that were modeled in our forecast, as well as the growth rates that were used by Asish to influence the PV adoption.

And I wanted to start by just setting the new model, the revenue requirement model into the context of the IEPR forecasting process.

There are a number of inputs that are going into this model and a number of the assumptions made. And I'll be going through those, as well, to give you a sense of what the vintage is of each of those inputs and assumptions.

In general, these rates were developed in April, in the April and March time frame. And so, really, much of the current activity, both at the PUC and the proceedings, as well as internally have not been incorporated into these projections for the preliminary. But we anticipate the staff will be looking at those to incorporate them once we go and generate the revised rates.

So, in particular, there are some GRCs in some ARRA proceedings that have not been incorporated into this and we want to make sure that we've gotten those in to the final set of numbers.

It's also anticipate that once the values are updated for the revised that we will be passing the projections on to the CPUC staff for vetting, so that we're attempting to be consistent with their understanding of how rates and things will change through the forecast period.

So, broadly speaking, the new model was used to create three rate case sets that are then utilized and correlated with certain demand forecast cases.

So, in the low electricity rate case, we have basically used low natural gas rates, lower carbon prices, and used higher sales to distribute those costs over, which led to a lower general rate for electricity. That is, of course, associated with the high electricity demand case and lends itself to a higher demand, obviously. Lower prices, you know, typically would have higher energy demand, given all things equal.

Under the high electricity rate, we are using high natural gas prices, high carbon prices, and we have a set of a lower sales over which to spread all of the fixed costs, and other costs, and that lends itself to a higher general rate.

The mid-case is just a set of assumptions which provide a mid, a rate case and it's associated with the middle energy demand case.

So, this table shows all of the data sources that are used in the preliminary electricity rate forecast. So, for many of these, you'll note that they reference either the CED-2014 update or a set of preliminary numbers that were generated for our demand forecast.

So, for example, the demand efficiency and distribution generation row is really using the update values from 2014 as the basis of the -- of those inputs. So, once we have developed a set of preliminary numbers, or the preliminary forecast numbers will actually be used as the basis of the revised forecast.

Likewise, the natural gas numbers, as I mentioned, were early NAMGas outputs from earlier this year. Those are what are being used as the basis of this. But we already know that those will be updated as we move through the IEPR cycle. So, we fully anticipate having some updated natural gas prices incorporated into this analysis.

Likewise, the GHG prices were also preliminary in nature and we anticipate updating those.

At the bottom, you'll notice there are a few lines for distribution, transmission and public purpose programs. These are currently in the preliminary set of numbers, they are even utilized in the preliminary demand forecast, are constant across all cases.

Staff anticipates, certainly, at least looking at the distribution component of costs and trying to develop a set of variables or variable costs across each of the three price cases. And that's something that staff will do before the revised forecast or the revised projection of electricity rates are produced.

CHAIR WEISENMILLER: One of the areas we may want to double check with the PUC staff, too, on is the renewable percentage. This is 33 across the board. My impression is one of the utilities will probably hit 40 like next year or so.

MR. WENG-GUTIERREZ: Right. That popped out to me, as well, when I looked at this. I didn't hear from Lynn about how she was anticipating looking at a varying degree, given the Governor's goals, as well as the 2030, 40 percent sort of numbers that had been put out.

So, I know that she had 33 percent across all three cases. I'm sure she would be open to looking at varying the renewable values across the forecast.

CHAIR WEISENMILLER: Yeah, I guess the other general question, up front, is do we have a sense of the utility balancing accounts, whether they're pretty much zero, or whether there's negative, positive? I mean, this always affects retail rate forecast.

CPUC COMMISSIONER FLORES: Yeah, I think the Southern California utilities have some fairly significant, you know, amortization of under-collections going on. And I wouldn't be surprised to see that moderate in the future.

I'm not sure about PG&E. But I think with all the rate-making around San Onofre, there was a buildup of under-collection, some of which was mitigated by the settlement, but not entirely. So, there may be, I think particularly in San Diego, it seems like the current rate is a little higher than what you expect as a long-term trend.

MR. WENG-GUTIERREZ: Yeah, and my understanding is that Lynn has looked at the balancing accounts through, basically, earlier this year. But we'll be looking at those as we progress through the summer and she gets a better idea about how those might be playing out in the near-term prices. But I think she did take a look at those.

The only other thing I wanted to mention here was that the transmission component here, I'll talk in a little more detail in a few slides. But it is constant across all the cases, but it is utilizing a tool generated by the California ISO to estimate transmission costs, and so that's the basis of it. And that tool is updated on a regular basis.

Taking a look at the natural gas component, these are basically breaking out the HUB prices for PG&E and Southern Cal Gas, or SoCal Gas. And you'll note that the SoCal Gas values are high. In the high case, are the highest of all of them. And that really reflects high natural gas demand from generation, as well as growth in the industrial sector demand in that region, lending itself to that high rate.

And you'll also note that in the following slides that this high natural gas price does influence the general Southern Cal Edison and other electricity rates more so than, say, for PG&E because they are higher in the high case.

So, here's the transmission access charge trend line that's used as the input for the forecast. Again, it's constant across all three price cases. The model, itself, I think generates values through 2021. Staff used a flat 2 percent real growth rate after 2021. So, that's why you have a linear trend upwards there at the end.

In general, these TAC charges represent high voltage costs. And the model that's used or generated by the Cal ISO is estimating these TAC rates based on known projects that they are incorporating into the tool.

This table just provides you a breakout of the costs in the associated annual growth rates for each of the elements of the revenue requirements that are generated or that are used to generate the three rate cases.

And, as noted, the distribution transmission costs are constant across the three cases, for each of the IOUs presented here.

I believe Lynn anticipates looking at, again, creating a set of variable numbers or growth rates for the distribution component. I don't believe she anticipates on doing that for the transmission component. But certainly, in the revised rates we probably will see a set of variable distribution costs.

The other thing I wanted to say was that staff did take a look at how responsive some of the prices were to changing natural gas prices, and found that a 10 percent increase in HUB prices generally led to a 1.5 percent increase in the bundled rates. It probably would vary, depending upon how the individual utility would have -- you know, what mix natural gas comprises their revenue requirements and their costs but, in general, is about a 1.5 percent increase for a 10 percent increase in natural gas prices.

Now, I'm going to show a few slides that basically show these for different sectors. It's just representing all of the rates in 2013-2026 across the different planning areas. And this is for the residential rates area.

The higher natural gas prices in the south lend itself to a higher variation here. And then, you know, I think there's generally a lower distribution cost associated with SDG&E. It's sort of hard to distinguish here that the variation across from the -- from 2013 to 2026. But some of those things are the contributing factors as to why there is a difference between, say, SCE and some of the other areas.

The POU rates are based on the IOU growth rates, but they also calibrated to actual rates. So, that it was the method used for the POUs.

This is a very similar slide. It's just showing, actually, the mid-case planning area results for the commercial rates. Again, it's difficult to see the impact of, say, the high or the different rates. But you can see that there's a variation across the different utilities and planning areas from 2013 to 2026. And it gives you an idea of the magnitude of the change across our forecast time period.

COMMISSIONER MC ALLISTER: Malachi, it might be good to see sort of these same utilities sort of as a percent growth per year, or something like that, to kind of distinguish, to be able to see the differences a little bit better.

MR. WENG-GUTIERREZ: All right, yeah, that would probably be helpful. I did take some time to think about how it might be better represented. I know the percent annual growth rates were showed in some of the other slides so -- but you're right, on an overall basis it would probably be good to show the aggregate growth rates.

COMMISSIONER MC ALLISTER: Also, I assume you have individual conversations with each utility, kind of to get them to tune into this or --

MR. WENG-GUTIERREZ: I'm not clear what conversations Lynn has had.

COMMISSIONER MC ALLISTER: Oh, right, yeah.

MR. WENG-GUTIERREZ: Again, she's the one who generated these. I know that she has been looking closely at all the proceedings and the activities that are associated with the revenue requirements. And plans, again, to vet them through the CPUC staff.

But I know we have had conversations, on the forecast side, about doing comparisons between us and the utilities to see, to determine what are the differences. And rate has come up in those conversations. But I'm not sure if Lynn has had other, independent conversations with them.

COMMISSIONER MC ALLISTER: I was thinking more of the POUs, than the IOUs, because I know you talk with the IOUs quite a bit.

MR. WENG-GUTIERREZ: Sure.

COMMISSIONER MC ALLISTER: But some of the smaller POUs, you know, that are on this graph might want to have that discussion, as well.

MR. WENG-GUTIERREZ: Okay, right.

COMMISSIONER MC ALLISTER: Well, SMUD's always here but --

MR. WENG-GUTIERREZ: Yeah.

COMMISSIONER MC ALLISTER: But like a Burbank or, certainly, DWP, you know, I'm certain would --

MR. WENG-GUTIERREZ: Right, right. All right, and then just to show the sort of variation across the different preliminary -- or the rates of growth across the different cases by utility.

So you can see, again, in the high demand case or which would correspond to the low electricity rate case, there is a significant amount of variance between the low and the high cases for, say, SCE, more so than, say, for SMUD. And that really is what's presented here.

So, although this doesn't provide you with a table of the annual growth rates, this does give you a sense of the annual growth rates across the different planning areas.

And this final table is just a comparison of the CED-2013 rate cases for -- this is a residential mid-case comparison between the 2013 numbers and then the preliminary 2015 numbers.

And I think the biggest element here to note is that the 2013 numbers, in the CEC-2013 Final, were estimated values as opposed to what is being utilized in the preliminary CED-2015 numbers, which are supposedly actual values, and so better reflect current rates.

And beyond that, you see that across the different planning areas there are certainly some that are higher and some that are lower. But in general, I think they're -- by the 2024 time frame, they tend to be on the higher side.

And that was the final slide that I have, so I'd be happy to answer any questions that I could.

COMMISSIONER MC ALLISTER: I think we're good. Thanks, Malachi.

MR. WENG-GUTIERREZ: Great. Of course.

MS. RAITT: So, the next is we can break for lunch, if you want to go ahead and do that.

CHAIR WEISENMILLER: Let's just -- I was going to see if anyone has public comments, who's here now, but won't be here at the end of the day.

Obviously, if you're going to be here at the end of the day, hold on.

COMMISSIONER MC ALLISTER: You want to go ahead? All right, we have two cards, Steven and Melanie.

MR. KELLY: Thank you very much for giving me an opportunity to comment here.

COMMISSIONER MC ALLISTER: Absolutely.

MR. KELLY: This is very interesting. I wanted to talk, very briefly, about the demand analysis and that I think it's now time to put on the table kind of a non-traditional demand analysis.

We're moving into a world where we are increasingly penetrating clean renewables and a larger role for energy efficiency.

One of the things we talked about yesterday, I think this came up, was the fact that the impact of those two major trends is that there's a higher probability that you might have a generation occurring in times when there isn't demand to take it, the over-gen problem that we've been addressing.

And I actually think now is the time for this agency to take the lead on starting to think through the implications of that and how to deal with it from a demand perspective. How to either shift demand and take advantage of that clean resource or how to create new demand for that demand resource.

We have filed comments in the IEPR, generally, about this issue. But I think it's front and center in terms of the demand forecast, too, which is why I'm here today.

In my review of the preliminary demand forecast, I kind of read through it very quickly, but I didn't really see a focused attention on, for example, how can we take advantage of that clean resource for economic development?

We’ve briefly talked about the water/power nexus. IEP has raised that issue in the scope of this whole thing.

But I think, you know, to what extent would, for example, desalinization solve multiple problems and how would that impact the demand forecast?

To what extent would you shift --

CHAIR WEISENMILLER: So, the basic data, Poseidon, 35 megawatts.

MR. KELLY: Thirty-five?

CHAIR WEISENMILLER: That’s the largest single desal plant in the Western Hemisphere.

MR. KELLY: But if you did ten of those --

CHAIR WEISENMILLER: So, you’d have to do 30 of them to get to 1,000 megawatts. We’ve got more than 1,000 megawatts.

MR. KELLY: And I think that’s one element of a number of steps that the State should be considering to, essentially, absorb this over-generation. And I think now is a good time for this agency to take the lead in thinking through those.

For example, if it’s 35 megawatts for desal for one plant, does it make sense to consider more? What other options do we have on the table in terms of shifting this demand and take advantage of it?

So, I just am here to urge you to think -- start the process of thinking that through. We don’t want to wait until it’s 2022, 2024 and see that we’ve got a sizeable problem and haven’t thought it through.

CHAIR WEISENMILLER: Oh, no, it’s a good issue. I mean, certainly, you know, your suggestion on desal was good. We dug into it, as I said. When you think about the costs and all getting to even, say, 30 of them to get to 1,000 megawatts is well past our, you know, quality.

But I mean, but the basic message when you look at that, when you look at ZEV so, again, we’re talking, you know, depending upon how coincident the charging is, you like 600,000 will get you to 1,000 megawatts. You know, I think the imperative really drives you to think what’s right. You know, I mean, some of the other things we’re adding just are drops in the bucket.

And some of it, you know, the other problem with desal, obviously, is it’s baseload. You know, the 35 megawatts, they told me they’ve got about 5 megawatts they can swing because of storage. Well, we’ll take the 5 megawatts. But, again, it’s not a panacea, I guess is what I’m saying, in that sense. We need variable load to match variable supply, and we're still struggling to come up with that.

MR. KELLY: And I agree with that. I think it's a broad array of solutions here, and I don't think one thing will fix this.

But the other thing, we had raised the question of to what extent would like real-time pricing in over-gen periods help move demand? That's kind of a broader issue, I get there. But it is something that I'd just urge the agencies, across the board, to be considering and thinking about as we move closer to 2024.

CHAIR WEISENMILLER: No, I agree. And I think part of it, you know, is that while things were framed in a real drama part for the rate design decision, the fact that about five commissioners voted for real-time -- you know, for time-of-use rates is a huge step. It's a huge step for dealing with these issues.

Because we're going to be finding, again, variations on it either being over-gen or under-gen, depending upon what's happening to the intermittent resources. So, it's a much different world than where we were last year.

MR. KELLY: Yes, I agree. Thank you.

COMMISSIONER MC ALLISTER: And I want to add, you know, I certainly agree with the imperative there.

The future of demand is not more of the same.

But we heard about a few things and there are many other things going on. You know, some of the behavioral staff is digging in and got several contractors on to look at some of these behavioral issues and what impact rates do have. And we've sponsored a bunch of research about that.

And the Energy Commission really has, you know, been an advocate of time-of-use rates for decades. And I think we're seeing that, really, the technology, the confluence of events and technology that we have today is really enabling that the rubber hit the road on that stuff. And so, that's incredibly exciting.

We're having kind of the technology, you know, end-markets discussion kind of now, and it's all kind of baking, really. And so that allowing us to really have the conversation, okay, well, policy, at the policy level what should we be pushing to implement that?

And so, I think there's still some questions about, okay, well, what are the costs of various scenarios, and how much should we really be investing on the demand side, and enabling, you know, manipulation of demand through markets? What's the avoided the cost of that in terms of, you know, the distribution grid, and investments that would otherwise be forced there?

So, I think, you know, please keep chiming in on this because I think it's really an active conversation. And I don't know that we know exactly what the right answer is today.

CPUC COMMISSIONER FLORES: And I would note, also, that the PUC decision not only endorses time-of-use rates, but very much focuses on it's not a one-size-fits all. I mean, there will be one rate that's the default but, you know, the decision definitely contemplates optional rates, with bigger differentials to try to recognize the very thing you're talking about.

And a lot of challenges ahead but, hopefully -- and we're going to have working groups, and certainly invite you to participate in those, in formulating what the TOU rates will ultimately look like.

MR. KELLY: Great. I think, ultimately, it will take a couple IEPRs. So, I'd just encourage you all to put the issues out there, now, so we can have that discussion.

COMMISSIONER MC ALLISTER: Well, I guess maybe there's a question for the forecasting team as to whether the methodology is kind of there, already, to be able to do some of this work. To see, okay, how might we categorize that wedge, whether it's desal, or hydrogen generation, or any other way to absorb some of the demand, or some of the excess supply.

MR. KAVALEC: I'll just make a brief comment based on what I think I heard. And that is I believe that our analysis going forward needs to be more integrated in terms of supply and demand. We tend to do one piece and hand it off to someone else and they do their analysis, and so on.

But we know the line between supply and demand is blurring. And so, my recommendation going forward is to think about more integrated analyses that bring together a lot of these questions, both on the demand side and the supply side.

COMMISSIONER MC ALLISTER: Totally agree. And one thing I would ask Steven, so that's kind of a big idea that IP's pushing and, you know, that's a good thing. You know, sort of what the business model for that idea looks like, and sort of put some numbers on it, I think would be really good. You know, how might that happen vis-à-vis the Coastal Commission?

Or, you know, I mean there are a lot of ideas we can -- you know, a lot of potential barriers we can imagine to that. So, you know, what would that look like in practice might be a good thing to develop.

MR. KELLY: I'm obviously happy to work with you on this. I mean, to lean on your staff a little bit for fleshing out some of the details of this.

COMMISSIONER MC ALLISTER: Well, I was kind of hoping you could do that and so our staff could focus on what they're doing, too. Bring it as baked as you possibly can.

MR. KELLY: We will cooperate. Thank you.

COMMISSIONER MC ALLISTER: Melanie Gillette, yeah, go ahead.

MS. GILLETTE: Thank you. Melanie Gillette with EnerNOC. Appreciate the opportunity to go now. And thank you, Commissioner McAllister, for teeing up my comments perfectly.

They definitely go to what Chris presented this morning, this issue of how load-modifying demand response resources are currently reflected in the forecast. And the issue that's identified in the draft report, and that Chris alluded to this morning, that maybe additional programs will need to be included.

And I know this argument is certainly not new to Commissioner Florio. We're very active at the PUC and have raised this issue several times. We're very aware of the potential study. We're involved in the working groups on both the load modifying and the supply side, and we're doing our best to stay engaged as we look to integrate demand response into the supply side. But we, of course, have an opinion on perhaps how much of the currently defined load-modifying resources will participate on the supply side.

And as you all know, with the bifurcation of demand response at the PUC, resources that are dispatchable and have been treated as supply side, are now defined as load-modifying resources, particularly the Aggregator Manage Program I'm referring to, now.

And so, this issue comes up. You know, currently, I think we have about 200 megawatts. And I don't know what that number is, all the aggregators all in. But Commissioner Florio might have an idea. But we think it's significant and we will have more in 2016.

And the immediate concern is that we don't have a final decision, yet, on the demand response auction mechanism, but we anticipate that soon.

So, it's everyone's expectation that there will be some percentage of these load-modifying resources participating in the auction. They're not included on the supply side forecast. They're not included on the load-modifying side, either. And I don't know exactly what those megawatts will be. I think there's a cap, maybe, of 15 megawatts. I'm not certain about that.

But anyway, that's our main concern is where are these being counted? And we think it does definitely go to the fact that the forecast for demand response is showing no growth. And our concern is, is that in part because these resources that we think are a significant number are not being included on either side, currently.

And we understand that there's an expectation that that definition will have to be expanded. But we're talking about resources in the market, in 2016, so it's a near-term concern. And we expect that those pilots will go for two years, I believe. And then we anticipate you will see more.

So, just raising the concern. I'm happy to, again, elaborate on it in written comments. But thanks for the opportunity.

COMMISSIONER MC ALLISTER: Thanks, Melanie. I guess, Chris, is that a -- is there a response or sort of the DR forecast and how it's treating some of those resources that Melanie referred to?

MR. KAVALEC: Yeah, I think the idea going forward is to do what we did -- we've done with committed and uncommitted efficiency. So, we would have DR impacts in our baseline forecast that are determined by programs currently in place.

Then, we would have results from potential studies, presumably, that would allow us to increase the rate of growth of DR impacts beyond what's currently in our baseline forecast. So, that’s the way I see it going forward.

COMMISSIONER MC ALLISTER: Thanks. So, we have a couple people on WebEx.

MS. RAITT: Right.

COMMISSIONER MC ALLISTER: Probably want to just give everybody the chance.

MS. RAITT: Okay, so Yaman Nanne, go ahead. Yaman, you’re line is open, if you had a comment.

Okay, should we go on to the next one?

Sierra Martinez, go ahead.

MR. MARTINEZ: Hello, can you hear me?

MS. RAITT: Yes, go ahead, please.

MR. MARTINEZ: Hi, my name is Sierra Martinez and I’m representing the Natural Resources Defense Council. Thank you, Commissioners, Chris, Malachi, and Anish for the presentations today. This is a tremendous undertaking and we appreciate your effort to develop a statewide demand forecast.

We commend you for making improvements on the previous demand forecast, particularly with creating a locational scheme, accounting for climate change impacts, and updating PV impacts.

I’d like to make two comments on energy efficiency and one question on rates.

The first, on energy efficiency, when the energy efficiency impacts were projected, it appeared to be a declining shape for savings. And I want to note that that is because the additional achievable energy efficiency impacts have not yet been included. That declining load shape is reflective of the fact that no future programs and no future codes and standards have yet been accounted for.

The second is that the forecast that accounts for the additional achievable energy efficiency more accurately reflects actual consumption. So, I look forward to seeing that additional achievable energy efficiency included in the revised forecast.

The second comment on energy efficiency is with regard to the uncertainty demonstrated from EM&V impacts. And I appreciate your demonstrating what the reduction is due to the 2010 to 2012 EM&V report. And I'd like to note that one additional year of energy efficiency program savings fully accounts for that reduction.

And with the POUs, it more than accounted for that reduction. So, when we're thinking over the long-term demand forecast, over 10 years, how much uncertainty there actually is in energy efficiency, it's more or less one year forward or backward.

My question on the rates was when it was presented in an overall fashion, were those nominal increases in rates or real increases in rates? Because over the last decade, rates in California have not been increasing much more than inflation. And so, accounting for inflation, around one or two percent, per year, would eat up a lot of that projected growth. Thank you.

MR. WENG-GUTIERREZ: So, this is Malachi, Sierra. My understanding is those are real growth rates. So, I can check back with Lynn about that. But those, I believe, real growth rates.

MR. MARTINEZ: Thank you.

MS. RAITT: Okay, should we give the folks on the line an opportunity?

COMMISSIONER MC ALLISTER: Do we think the other WebEx person dropped off? It looks like it. Yeah, let's do the phones.

MS. RAITT: Okay, so please mute your lines if you're on the phone, unless you have a comment, because we're going to open up the lines.

I think we're good to take lunch.

COMMISSIONER MC ALLISTER: Thanks everybody, we'll see you back here at one o'clock.

(Off the record at 12:08 p.m.)

(On the record at 1:02 p.m.)

MS. RAITT: All right, welcome back to the IEPR workshop on the Preliminary Electricity Demand Forecast.

So, for the afternoon we have Malachi, again.

MR. WENG-GUTIERREZ: All right, good afternoon. My name is Malachi Weng-Gutierrez, still Malachi Weng-Gutierrez. And I will be going over a number of the planning area specific forecasts this afternoon. I will be covering the IOUs and then Cary Garcia will be following me with the POUs.

I'm hoping that after each of the planning area forecasts that we present, we will open it up for the opportunity for the utilities to come up and make comments.

And I'm going to start off with Pacific Gas & Electric. So, as Chris mentioned this morning, we redefined the planning areas to be more consistent with the transmission access charge areas that Cal-ISO uses. This significantly changed the planning area associated with PG&E. So, instead of having five climate zones that we had in the previous IEPR, or previous update, the CED-2013 and 2014 updates, we now have six climate zones.

In general, the electricity consumption grew in this area relative to the update in 2014. However, with the increase of the adoption of PV, we see that the sales in peak forecasts are down.

In general, we've seen a migration inland, towards those climate zones in the Central Zone of California. And that is borne out, you'll see it borne out in the growth of the climate zones associated with those regions in the PG&E territory.

So, since there is a difference in the planning area definitions, it's not possible to do a apples-to-apples comparison between the updated preliminary mid-case and the update in 2014. But we can take a look at the growth rates between the two mid-cases to see how they are growing in comparison to one another.

And they are fairly close, 1.25 percent for the new mid-case versus a 1.29 percent in the update. However, I haven't provided the trend line for the update in 2014, again because it's just not an adequate comparison because of the redefinition of that area.

However, for sales, the planning area -- although the planning area definition has changed, we did do some processing to evaluate and break out the utility by the new TAC area definition. So, we can do an actual comparison between the two. And, therefore, the 2014 update value is presented here as the red line. And you'll note that it is significantly higher. Not only is it higher than the new values, but in the mid-case, if you were to do a comparison between the two, you'll note that for the new mid-case it's actually growing at a slower rate over the forecast period. And that's, again, due to the higher adoption of PVs.

The starting point, the difference between the starting points, obviously, is pretty significant. And that really is a factor due to the rates, differences in the rates that we're using. We have a higher set of rates to utilize this time, which lowers our initial starting point.

And the impact, you'll note here in the actual peak demand associated with PG&E, that the mid-case for the 2014 update is running along the high case in the new update for the 2015 forecast.

So, but in general, all of the cases that we have now are lower and that does make sense given the set of assumptions that we're using.

This is in actual net peak demand, so this accounts for the new generation, as well as the actual peak.

So, as Asish mentioned earlier today, the PV energy is significantly higher in our new projections, in the preliminary forecast. In the case of PG&E, it's about 150 percent of energy that was seen in the update for 2014. So, our mid-case is significantly higher and for all of the reasons that he mentioned this morning.

This may be revised slightly as we go forward. And Asish mentioned a number of factors that he's going to include in evaluating the PV in the future, and for the revised forecast. And we anticipate that all of those will -- may impact how these PV energy is distributed across the different planning areas.

So, in this case we're looking at almost 6,000 gigawatt hours of difference between the new and the old cases in the 2025 time frame.

So, you might imagine that the increase in PV energy would contribute more largely to the PV peak impact. But as Asish also mentioned this morning, that the peak conversion factors were actually, also adjusted. And, therefore, the amount of actual peak impact associated with the new PVs is not as significant as you would imagine.

And in this situation, in the 2025 time frame, it's about a thousand megawatts difference between the two mid-cases in 2015, which is pretty significant, still, even with the conversion factors.

So, with the plug-in electric vehicles we, as Chris had mentioned this morning, we updated some of the values for the regions, for the different planning areas, and have reflected near-term sales to adjust what we had produced in the 2014 and the 2013 IEPR forecasts.

In this case, for PG&E there's a difference between the two, but it's not as significant as in other planning areas. So, you see that we're slightly above where we were for the update, but fairly comparable.

And as Chris mentioned this morning, there is an intention that we will be bringing, certainly, the plug-in electric vehicle topic to DAWG meetings in the future, and we'll be working with the Transportation Office, as well, coming up with what will be, eventually, incorporated into the revised forecast.

All right, so I'm going to make an attempt to explain this. I know Chris explained it on a statewide basis, and it's going to be a similar explanation here.

The red line here is really the reported savings that is not adjusted for anything. Then, accounting for the recently completed EM&V study that evaluates the realized savings from the different program areas, for the 2010 to 2012 time frame, we used the results of that study to create an adjustment factor which we applied to the previous reported values.

That leads to the blue line that's here. And then on top of that, for the 2015 time frame, we add on the program savings associated with 2015, and that gives us the green line.

So in aggregate, if you were to look at what was incorporated into the preliminary forecast, it really is a composition of the blue line, from 2010 to 2014, and then the green line, from 2015 to the end of the forecast period.

Looking at the growth in electricity consumption for the different climate zones within PG&E, again, these are the newly defined climate zones, we see that the Greater Bay Area has a significant amount of growth relative to the others, primarily due to commercial sector growth.

You also have growth in the Central Valley and Central and Southern Valley area, partially driven by commercial growth, but also by the inland migration and the population growth that we're seeing in those areas.

Now, this is significant in how that growth represents itself in peak demand, in that in the Greater Bay Area, since the commercial sector is growing, and you also have a higher amount of PV adoption, you don't see as a high an annual growth rate for the peak demand.

Whereas in the Central Valley and the Southern Valley Region, you do see a significant growth rate for the peak demand. And that's really due to the fact that the growth is occurring in the residential sector more than the commercial, as well as you have a much more hot climate region in the valley. And those end uses associated with the residential sector are much more sensitive to that heat. So, you still have a significant amount of growth in the Southern and Central Valley climate zones.

So, staff sat down with the utilities, for each of the different planning areas, and discussed the forecasts that we had generated, and their forecasts, and did a comparison to see how we measured up against one another and what elements we probably would want to look at working through, when we go into the revised forecast work.

And for PG&E, in general we found that their sales were higher and it's because of a number of factors, and they're presented here. Higher starting point. They had a slightly higher EV forecast than we did. And they had lower growth in the electricity rates. And then, they also had a higher industrial forecast.

We'll be looking at each of these points with them, over time, and looking at what the differences are. And if, in fact, we would be making some changes to our forecast for that planning area, specifically.

Given that, the peak demand forecast was pretty close between the two, if you didn't account for the starting point. So, the growth rates were fairly similar to one another. And then, the PV forecasts were actually fairly similar.

So, in general, we felt that it was a pretty decent comparison. We'll be looking at the sales information a little bit more closely. But, in general, I think we felt it was a decent comparison.

And I think that's the end of my slides. So, if there are any questions, I'd be happy to try and answer them.

CHAIR WEISENMILLER: Yeah, I've got one, which is just trying to understand, in terms of the PV forecast, how did that vary across the different zones?

MR. WENG-GUTIERREZ: Asish, do you want to --

MR. GAUTAM: Let's see, for the residential we saw more growth in the inland because that's where the housing starts were going faster. But I think we still show quite a bit of growth on the coastal area because of the historical adoption occurring there.

I don't think we received any kind of PV forecast from PG&E about the different zones, so I'm not sure how to --

CHAIR WEISENMILLER: Yeah, I was going to suggest one of the areas going forward, certainly, would be to encourage -- it's good to get the overall numbers lined up. I'm sort of curious, particularly when we do transmission planning and all, you know, how it varies across the different climate zones.

MR. WENG-GUTIERREZ: Okay, so we'll --

CHAIR WEISENMILLER: I'd like to think that it's going to be more and more in the inland area, and having affects there. But, you know, as I said, eventually we need to be syncing over to some distribution planning.

MR. WENG-GUTIERREZ: Right.

CHAIR WEISENMILLER: So again, the more -- obviously, there's a limited granularity, but at least knowing whether it's in San Francisco, or Central Valley, it would help.

MR. WENG-GUTIERREZ: Right. And I think -- well, I mean Asish can speak to the factors that are influencing the adoption in the different climate zones, as he sort of alluded to there. But I would assume that, yeah, the number of housing starts versus the income distribution would change the adoption in the different regions, as well.

MR. KAVALEC: And I should mention that we're still in the process of transitioning our models into the new geographic scheme. So, what Asish did -- what Asish does in his model is he forecasts at the climate zone level, but it's for our old climate zone scheme.

So, I had to map those to our new climate zones. So, it's an imperfect mapping.

But as time goes by, our models will be set up to forecast specifically, including PV, for the new climate zones.

COMMISSIONER MC ALLISTER: But you'll be asking for that, that data by the new zones, from the utilities in terms of PV interconnection, and growth rates, and all that?

MR. KAVALEC: At what level do we get the data, now?

MR. GAUTAM: Right now, we've asked it for by zip codes, so assuming we have --

MR. KAVALEC: Yeah.

COMMISSIONER MC ALLISTER: Great. I'll say the same thing about EVs, as well, right. I mean the adoption, we need to know those by geography. And we've funded some stuff on that, lately, and I think there's some good work going on with the incentive program data to sort of figure out where the EVs are going, and what the growth rates look like in different parts. So, that would be very relevant, I think, for the distribution planning.

MR. KAVALEC: Yeah, and as I mentioned this morning, we get a statewide forecast that we attempted to distributed to the different planning areas and climate zones. But I think, ultimately, the answer is at some point, given enough resources and time, our Transportation Unit actually does these projections at a much more refined geographic level so that -- we did a distribution, but it was relatively simple, with a regression. It would be great to have an EV forecast from the ground up, at a much more disaggregate level.

MR. WENG-GUTIERREZ: Yeah, and our starting point for the EVs is we have a very good starting point because of both the rebate program data, but also the DMV database that we have for the registration. So we know, basically, where the vehicles are to begin with. It’s just where are they growing and why is the distribution of vehicles getting distributed the way it is? And that’s where the regression this time around came in.

COMMISSIONER MC ALLISTER: Oh, okay.

MR. WENG-GUTIERREZ: It’s sort of a new method. In the past we had used flat sort of rates, given today’s different -- you know, distribution across the State. If we use those constant, it wasn’t really adequate and we had some comments back in 2013 about that methodology. So, this time around we’re doing something a little more refined but still could use, certainly, some improvement.

COMMISSIONER MC ALLISTER: Great, thanks.

MR. WENG-GUTIERREZ: So, I think, if there are no more questions from the dais, do we open it up for the comment, then, from the utilities? Yeah.

MR. MULLAR: Good afternoon, Commissioner McAllister and Commissioner Weisenmiller.

On that last point, I'll just go straight from the prepared comments. And our DER expert is telling me that we actually have a lot of that GS spatial forecast date in our recent EDRP filing. So, I would suggest having a good look at that and we can talk offline about some of those details.

But anyway, so my name's Dave Millar. I take primary responsibility for developing PG&E's annual electric sales and peak demand forecast, which we've submitted as part of the IEPR forecast.

I work with a broad team of experts, who specialize on the issues we grapple with as forecasters, including understanding the effects of future energy efficiency, distributed generation, demand response and electric vehicles.

As you know, we live in an era of, you know, great uncertainty with respect to forecasting the future state of the electricity system. We are clearly seeing a severing of the formerly ironclad link between economic growth and electricity growth due to efficiency in PV. And we now see flattened, declining sales as the new normal for the foreseeable future.

We applaud Chris and the CEC staff for their efforts to undertake this difficult task. And we are pleased, and generally in agreement with the forecast, with respect to both sales and peak.

So, on distributed generation, the CEC team has worked with our subject matter experts to better understand how we forecast DG. And we recognize, as Chris stated in his presentation, that we are now much closer in our assessment of growth of PV in our territory.

We understand that the increase in CEC's PV forecast is driven primarily by the revision of the approach, now that they use tiered residential rates and hourly load profiles to estimate bill savings from PV, rather than average rates and usage.

While we believe this is a significant improvement, and as Asish alluded to in his presentation, we recommend that the CEC move away from the payback method measure of cost effectiveness in its retail PV self-generation forecast.

Under the current residential PV market

environment, in which zero down financing mechanisms predominate, we believe this can -- the payback method can result in under-estimates of future adoption.

Instead, we recommend that the CEC use an approach that compares bill savings to typical prices for solar leases and PPAs. Again, we want to underscore the suggestion to explore this further in a DAWG workshop broadly on DG forecasting. On energy peak impacts, certainly. Also, to look at some of the non-PV forecasts, including we see growth in fuel cells and CHP, where I think in the CEC forecast it's pretty much flat.

On electric vehicles we also agree with the recent revision to the forecast. Our forecast is based on -- also based on certain near-term PEV adoption, registrations that we're seeing in the near term. So, a one percent growth every month. So, pretty fast growth, although from a small base.

And in the long term, our forecast is generally consistent with Governor Brown's goals and the ZEV action plans.

As Chris pointed out in his presentation, you know, we do differ on our rate projections. And we believe that average rates will grow much slower than assumed in the preliminary CED. And this is primarily due to expectations of lower procurement-related costs.

PG&E recommends that CEC revisit any -- we know you will, but recommend that you revisit the rate forecasts in the context of our recently submitted forms, 8-1-A and B, which show our forecasted long-term revenue requirements that we believe would likely result in much more modest growth in rates.

And going forward, we would like to have some more involved conversations with your team on rate projections.

We also note that our industrial sales forecast is higher. One of the few areas of sales growth that we have seen is from the industrial sector. Which, if you control for the departure of one of our largest customers, it has grown about 8 percent since 2010.

So, we would like to continue to work with CEC to highlight the positive growth trends in this sector and discuss how to account for the level of adjustment in the loss of that large customer.

On peak demand forecast, also we agree with the assessment that our trends are similar, but that we do differ on the starting point in 2014. We suggest continuing to explore the issue of peak weather normalization at future DAWG meetings.

So, that concludes my formal comments. I can try and answer your questions. Like I said, our expert on DR is here, so if you have any hard questions, you can ask her. And I can direct, so that's it. Thank you.

COMMISSIONER MC ALLISTER: Just one or two questions. So, could you elaborate a little bit on the industrial demand and sort of what your departing was, or looked like and --

MR. MILLAR: Sure, I can.

COMMISSIONER MC ALLISTER: -- where are you seeing growth in terms of what kinds of activities and where?

MR. MILLAR: Yeah, so I can't name names of our customer, but it was one of our largest customers, period, who went off grid and went to self-generation.

COMMISSIONER MC ALLISTER: Oh, okay.

MR. MILLAR: And that happened in 2013. So, it was a very large departure. So, if you don't control for that, you'll see maybe declining growth. When, really, the underlying fundamentals show that there's growth in that sector.

You know, we do our forecast econometrically, so we're not looking at each, individual customer. So, we'll have to do a little more research on where the growth is coming from, particularly. But again, this is one of the few areas, that and agriculture, where we've seen growth.

COMMISSIONER MC ALLISTER: And agriculture.

MR. MILLAR: Yeah, mostly drought related.

COMMISSIONER MC ALLISTER: Yeah.

CHAIR WEISENMILLER: Okay. Well, I guess for the demand response question, I just wanted to understand, as we're doing the load modification approach, again how well we can sync up that, particularly on a geographic distribution.

MR. MILLAR: Yes.

CHAIR WEISENMILLER: So, I don't know if we've had any discussion or exchanges back and forth on methodology, or numbers with PG&E?

MR. KAVALEC: I mean, for demand response?

CHAIR WEISENMILLER: Yeah, the load modifier part of it.

MR. KAVALEC: No, we haven't.

CHAIR WEISENMILLER: Okay, so that would be another area to follow up on.

MR. KAVALEC: Yeah. But again, this is based on PG&E's DR MEC (phonetic) submittals, as vetted through CPUC.

CHAIR WEISENMILLER: Okay.

MR. KAVALEC: So, hopefully, we're in somewhat in alignment. It's the same data sources.

And on the industrial sector, I'll just mention that I think a comparison of methodologies is in order. We've looked at the data, too, and we don't see, even looking at the near term and adjusting for a departing customer, we don't see the same growth. But this may be a function of the methodologies we're using, so we'll have a sit down with them.

MR. MILLAR: There might be some categorization things to iron out.

COMMISSIONER MC ALLISTER: It's always good, I think, to do the econometrics and that's necessary. But I think then to sort of true it up to what the realities look like and use a little bit of a gut feeling.

MR. MILLAR: Yeah, well, at least the recorded data is quite clear that we're on a very solid growth trend.

COMMISSIONER MC ALLISTER: Let's see, you know, I was going to ask another question, but I think I'm going to pass. So, good for the moment.

Why don't we move on to the next. Is Edison next?

MR. WENG-GUTIERREZ: Yes, so now we're going to go to Southern California.

COMMISSIONER MC ALLISTER: Thanks very much.

MR. MILLAR: Yeah, thank you.

MR. WENG-GUTIERREZ: So, yeah, now we proceed to Southern California Edison. The format's going to be very similar to PG&E. All of them are very similar to one another in the format of the actual presentation. So, I'll just go through them fairly quickly.

So, as with PG&E, the SCE's planning area was redefined slightly, and so there is a slight difference in what the planning area is comprised of. So, there might be some differences and difficulty in making a comparison between the update in 2014 and the current numbers. But we did have some post-processing, so we can do some comparisons.

Generally, the electricity consumption growth is down slightly compared to the update, and that's primarily because of a faster number of housing growth that was talked about this morning.

And then we also had a slightly lower EV forecast. So, the EV forecast is, sorry, slightly lower, but then we do have a number of households that are growing in the region a little bit higher than we had in the update, but they sort of counter one another.

In general, the sales in the peak are down. Again, more significantly because of the higher PV forecast. And again, we also have an inland migration, which leads to a different growth pattern across the planning area. So, those inland climate zones are going to see higher growth than those on the coast.

So, again, taking a look at the broad electricity consumption, we can't do a direct comparison because of the planning area definition change, but we can take a look at the growth rates and they appear to be somewhat comparable to one another; 1.06 percent in the new mid-case versus 1.13 percent in the update in 2014.

Then looking at sales, again, the new PV has led to a significant decline in the amount of sales that we're seeing. The PV adoption rates are fairly high compared to last time. And so, therefore, our sales numbers, if you compare the mids, are down.

So, if you look at the growth rates, even if the .55 percent per year, versus a .99 percent in the update, that's significantly different and we do have, in the 2025 time frame, a fairly significant difference there, maybe nearly 5,000 gigawatt hours.

Likewise, taking a look at peak demand, the number -- the amount of -- almost in all, nearly all cases here we have a set of lower numbers. And that, again, is because of the -- well, again, it's because the new case is about 1,000 megawatts below the update mid-case in 2025. Again, driven by everything Asish mentioned this morning, although we have higher adoption rates for PV.

The amount of generation here is significantly higher, as well. Similar to PG&E, it's nearly 150 percent of what we had generated for the update in 2014. That's a significantly higher amount. And again, it's because of the new tiered pricing and all of the other factors that Asish had mentioned.

Certainly, for SCE, there's a big difference here, 5,000-gigawatt hours between the new and the old mid-case by 2025, and that's pretty significant.

Again, counting for the new peak conversion factors, the magnitude of the influence on the peak impact is not as significant as you might imagine. Although, it's still significantly higher just because the magnitude of the adoption is much higher than we had in our update in 2014.

And the level here, in the mid-case, corresponds to about a 4,500-megawatt capacity increase.

Looking at the EV forecast, or the demand associated with the EVs in SCE territory, our numbers are a bit lower than they were last time. And again, this is partially due to updating the numbers for near term sales, but also, then, our new allocation methodology has contributed to this, I think, a bit.

And so, if you compare the two mid-cases, obviously, ours are significantly lower than it was in the update in 2014.

COMMISSIONER MC ALLISTER: Malachi, what's driving that, sort of between last year and this year, sort of seeing adoption slow down a little bit and you're taking that into account or is it just --

MR. WENG-GUTIERREZ: No, so --

COMMISSIONER MC ALLISTER: -- really, fundamentally, the model itself?

MR. WENG-GUTIERREZ: No, so the difference, the only real difference is that the near term sales were accounted for in this cycle. The variation that we're seeing from planning area to planning area is a product of the new allocation method we're using across the entirety of the State.

COMMISSIONER MC ALLISTER: Oh, okay, I got it. I got it, okay.

MR. WENG-GUTIERREZ: So, really, in general, if you looked at the statewide numbers that Chris presented this morning, it's not as significant.

COMMISSIONER MC ALLISTER: Okay.

MR. WENG-GUTIERREZ: And then, if you look back at PG&E's, they were fairly close. But it all has to do with how we're allocating the vehicles across the State, as a whole.

COMMISSIONER MC ALLISTER: Okay. It would be good to get Edison's view on whether that works for them.

MR. WENG-GUTIERREZ: Sure.

COMMISSIONER MC ALLISTER: And each utility talk about sort of whether this jibes with what they are experiencing in their territory.

MR. WENG-GUTIERREZ: Yeah, and I know that the EV topic is one that I think needs some discussion. And I'm hoping that, you know, any feedback that the utilities can provide and insights about how they think would be best to approach this would be beneficial. I'd be interested to hear what everyone says about this.

So, again, looking EM&V adjustments to the energy efficiency programs, I won't belabor it too much, but the red line is basically the reported set of values. The blue line is the adjusted savings values, accounting for the study results from -- the recent, completed study results for the 2010 to 2012 program savings. And then adding on top of that, the 2015 program savings, gives you the green line. So, again, overall what's included in the forecast would be the blue line from 2010 to 2014, and then the green line through the remainder of the forecast.

And as you can see, it ends up being the net effect of the adjustment and then addition of the 2015 savings basically cancel each other out, as Sierra had mentioned that they're pretty much comparable, the adjustment and the addition of the new savings.

Taking a look at the climate zones, the regional growth rates, we see some similar things that we saw in the PG&E territory.

The Eastern Territory's electricity consumption is growing pretty significantly. And this is due to commercial growth and also the hot weather in the east.

Peak demand here is also growing significantly in the eastern area. But we see that the Big Creek East Region, or the climate zone, actually has a significant amount of peak demand growth. And that really is because it's, again, a hot region. The growth here is in the residential sector, which is very sensitive to the hot conditions and certainly has those end uses which are temperature dependent.

And then the LA -- the other thing I want to note is the LA Metro Region, if you see here, it's not as high a growth rate as you might anticipate, given that the growth rate here is sort of comparable to some of the other climate zones. And that may also partly be because of the PV adoption in this region.

So again, with SCE we did a comparison of our forecasts, our forecast to the SCE's forecast. And we looked through them and came across a couple of things. SCE's forecast, in general, is significantly higher than our preliminary sets of numbers. They had a higher EV forecast and, you know, it was pretty significantly higher, 1,000 gigawatt hours. And so, of course, it will be interesting to see if they could -- or what they will comment on about our EV forecast.

And they had lower growth rates in general, in the nonresidential area, higher commercial forecasts, and then growth in actual sales in 2014. Which I think we had discussed with them, as well.

And then, they had included a significant impact to additional electrification, which we haven't really included that component, yet. So, it's something that we might be looking at including in the revised forecast, so that might true up our numbers a little bit more.

Peak forecasts in general were closer. And the difference between them really were attributed to the EV peak and the PV peak factors.

So with that, I think that's the end of my presentation, so I'd be happy to take any questions.

CHAIR WEISENMILLER: Yeah, I noticed -- this is Bob, again. My presumption is that, at least I think it was last year, the sort of additional electrification was an issue that certainly differentiated. So, I'm glad to hear we've got some onsite support to help in that area and presumably we can get a little closer. I know there's a lot of work, particularly around the ports, on electrification.

MR. WENG-GUTIERREZ: Yeah, and I certainly believe that's part of that contract work that we're interested in having the contractor weigh in on.

MR. KAVALEC: Yeah, and we've had Edison, as well as LADWP, involved in our electrification discussions with the contractor.

CHAIR WEISENMILLER: That's good. How about the port? I know, when I've met with the port, they had just very high growth rates for the port. And I think at this point, I think they're in the process of revising those. But, again, a lot of electrification, but also a lot of growth in what they were anticipating at the ports, too.

MR. KAVALEC: Yeah, and maybe Edison can tell us where most of their growth in the electrification is coming from, how much is from the ports versus other sources.

CHAIR WEISENMILLER: Right.

COMMISSIONER MC ALLISTER: Isn't there Federal -- aren't there Federal mandates coming around that say the ports have to do --

MR. WENG-GUTIERREZ: It's actually a State. ARB has an at berth regulation which requires certain fleets to be electrified, given how many times they visit the port, and the frequency of their visits and things.

So, they actually have to -- they're mandated to be electrified and there's a schedule of how often, how much of the time that they're at berth they have to be electrified and all of that. That's essentially a part of ARB regs.

COMMISSIONER MC ALLISTER: Okay, so that's ARB. I worked at the port in San Diego quite a bit, and they were trying to get ready for that transition, and get ahead of it and stuff. And, I guess, also thinking about drayage vehicles and things --

MR. WENG-GUTIERREZ: Oh, yeah, sure.

COMMISSIONER MC ALLISTER: -- really made the push to electrify their facilities, generally. But a lot of it was sort of a compliance issue where they had to get the boats off of, you know, dirty power.

MR. WENG-GUTIERREZ: Right, yeah. So, the shore powering is certainly part of the ARB regulation.

The other non-marine electrification is not necessarily associated with that specific reg. But I know there’s a lot of interest in it, a lot of demonstration projects. And I think staff has been fairly well engaged with the ports about those topic areas.

And I know, as part of the kickoff for the contract work that we’re looking at for electrification, the ports were invited and participated in some of that work, and contributed to informing that activity, as well.

And so, I hope that staff will continue to work with the ports to get a clear picture about what they see as the growth in those regions.

COMMISSIONER MC ALLISTER: Yeah, great. And then that’s a good opportunity to triangulate with the utilities and just make sure that everybody’s on the same page.

MR. WENG-GUTIERREZ: Of course.

CHAIR WEISENMILLER: And another group I’d add to it is the military. You know, we’ve been working pretty closely with them, and they’re also looking at electric -- you know, they have ports, really, and they’re certainly looking at electrifying those, also.

MR. WENG-GUTIERREZ: Right. So, I know Port

Hueneme and, well, San Diego, not the military component of it, but the San Diego Port and their passenger ships have to electrify, as well.

But yea, the military is another area that we're looking at and discussion.

CHAIR WEISENMILLER: Good.

MR. WENG-GUTIERREZ: All right, so if there are no more questions, then I think SCE's going to come up.

MS. SHENG: Good afternoon, Commissioners. Good afternoon, everyone. First, I'd like to thank the Commissioners for hosting this workshop and providing the special opportunity for stakeholder comments.

Second of all, I'd like to really compliment the demand forecast office at CEC for coming up with this challenging forecast with all the uncertainties we face in the future.

Also, I'd like to thank Chris Kavalec and his forecasting team for working really closely with SCE forecasting team throughout the forecast process, keeping us updated and bringing the common acknowledgement on the forecast differences.

So, for the forecast differences I'm going to talk about here, today, are pretty much the common recognition between our forecast teams. And we would really like to work with CEC forecast team addressing some of the significant areas for the revised forecast.

As Malachi mentioned, for the differences of our annual sales forecast, one of the main areas that we see the differences is really coming from our transportation electrification forecast. Our EV forecast is slightly higher and that's mainly driven by our assumption of higher electric vehicle sales in the future. And, also, the higher electric vehicle consumption in the future.

But I think we are positive that, you know, once CEC incorporates the additional transportation electrification load forecast, that's non-EV related, our forecast differences would be reduced.

So, we'd be happen to work with CEC and the Aspen Environmental Group to provide any inputs we have on this area.

One of the things that we pointed out before is there's a recently completed TE study that could be a really good reference for that area of forecast.

What I really want to highlight is our peak demand forecast differences, where we see the differences we have on the EV peak contribution and, more specifically, the solar PV peak load contribution. We have discovered that even thought our solar PV forecasts, in terms of capacity, are higher than CEC's, but when we look at the future peaking pack from the increasing solar PV load, we actually recognize that because SCE has accounted for the future peak hour shifting facts. So, we would actually see a decreasing peak impact from the increasing solar PV load for the future years.

So, I'd really like to highlight that fact and, hopefully, help everyone gain a better understanding of that.

So, this graph is created for illustration purpose. What we show here is the upper boundary reflects the typical Cal-ISO system peak day hourly load shape. As we expect, you know, we will add more solar PV capacity into the system at some point in time. You know, we expect, you know, additional 5,000 megawatt solar PV capacity into the system.

We would actually likely to see the peak hour shift from hour 17 to hour 18. As a result of that, when we account for the future solar PV impact to the peak hour, SCE is looking at a much reduced solar PV peaking pack, compared to CEC's forecast is looking at the increasing solar PV impact in the future because of the increasing solar capacity projection. And, also, assuming the same peak hour would hold constant into the future.

This actually creates a significant difference in our peak forecast, as you can see from the chart, by 2026. Our solar PV reduction would be 1,000 megawatts less than what CEC has attributed to the peak reduction from solar PV site.

So, what we'd really like to see in the CEC revised forecast is for CEC to incorporate the latest available information. And, also, consider incorporating all the additional potential TE load growth from the other sectors that's non-EV related.

And we'd be happy to work with CEC to examine the peak hour shift effect to reflect the appropriate solar PV impact.

In terms of the accounting for the uncertainty of the future TE adoption and TE related electricity use, we believe strongly that it would be great for CEC to take account of the governmental environmental goals into account.

And also, providing more transparency and consistency over the scenarios that we would develop for both the EV and other TE load forecast.

So, that's my comments. Any questions?

COMMISSIONER MC ALLISTER: Could you go back to the illustrative -- that one there. So, in that curve there, you know, the peak consumption moment hasn't changed, right, it's really just the net load has changed. That's right?

MS. SHENG: Right, it's net demand. This is all behind the meter solar PV generation. So, this has not -- this before accounting for the supply side of solar generation.

COMMISSIONER MC ALLISTER: Yeah, so I guess I'm trying to sort of parse that. I want to ask Chris or Malachi, the -- let's see, so you end up pushing the peak backwards. And so, you know, I get there. But I guess it doesn't -- or do you see consumption, itself, so apart from behind the meter or not, do you see consumption itself shifting into the evening or, really, just that's a function of the fact that you've got a bunch of PV on the grid.

MS. SHENG: Yes, the net demand, not the consumption.

COMMISSIONER MC ALLISTER: Yeah, so I guess it seems like, you know, it used to be that we talked about load factor and we looked at the -- you know, it was a one way system, and we had a load factor, and it had a peak, and that sort of was seasonal, and got bigger or smaller and we worried about those sorts of things.

But here, we're in a kind of more complex situation where we have demand and supply interacting. And so, I think I want to make sure that we're talking the same language between our staff and Edison about how to sort of quantify that peak effect. Because the fact is that an incremental marginal PV system that goes on still does, you know, at 1700 hours still pushes that demand curve, that net curve down, right.

MS. SHENG: Right.

COMMISSIONER MC ALLISTER: So, at the moment of peak consumption.

MS. SHENG: Right.

COMMISSIONER MC ALLISTER: Right. So, I don't necessarily -- I think reasonable people could have a discussion and come down somewhere in the middle in terms of how to quantify the peak reduction of PV. Because your net peak is already lower than your consumption peak, right? Anyway --

CHAIR WEISENMILLER: Primarily, earlier in the afternoon.

MS. SHENG: So, I think we are not simply looking at the peak of the consumption, but eventually looking at the net peak --

COMMISSIONER MC ALLISTER: Absolutely.

MS. SHENG: -- after accounting for the solar PV. That's just a natural effect of we adding so much solar PV into the system. And, eventually, we would be pushing the actual peak hour to later.

COMMISSIONER MC ALLISTER: Yeah, you know, I get that. I guess I’m just noting the fact that the actual peak hour is still lower than what the peak would have been -- than what the distribution system has to carry, I guess is what I’m saying.

MR. KAVALEC: Part of the confusion we always have is in the definition of the peaks. So, we always use a definition here of net peaks, that’s net of any self-generation.

But I think going forward it would probably be useful to also start reporting the customer peak, the actual end-use peak, and go from there to the net peak, rather than just reporting the net peak.

COMMISSIONER MC ALLISTER: Yeah, I mean, I guess I wanted to know maybe from Edison, but also the other utilities, you know, how is your -- under this scenario, where you’ve got a lot of behind the meter, some of it’s getting pushed out into the distribution grid, much of it’s being consumed on site. How is that impacting the way you think about optimization of the distribution grid? Like, does load factor actually even capture what’s going on before?

But, you know, I would like to know sort of what is your load factor evolution, is it going down?

MS. SHENG: Yes, we will see the -- load factor has been going up over the last decade, but we're seeing it's going the other way in the future. And that's an area I think it could also vary geographically. This is an area, definitely, we need to examine more, the changing fact, now that we have all kinds of DR resources that could impact both demand and supply side.

COMMISSIONER MC ALLISTER: Okay.

CHAIR WEISENMILLER: Yeah, I think part of the question is this is -- you know, there's a spatial and a temporal. So, a spatial, you have a lot of coastal fog which is going to affect things.

Temporal, this has like a 6:00 p.m. peak. So, the solar impacts vary throughout the year as you go from winter with, you know, basically the sun going down much lower, peaks being higher. And then in the summer, again, things shifting around.

So, I would assume summer peaks are probably closer to 7:00 or 8:00. And again, our peak peak is summer. So, again, I would anticipate that sort of diminishing contribution of solar, but it's going to shift throughout the year depending on when the sun sets and when the peaks occur.

COMMISSIONER MC ALLISTER: Yeah, totally. I'm trying to dig -- I mean, I think the details really matter here in terms of how you quantify that peak impact and, you know, what days you're focused on, what seasons. You know, yeah, like you say, geographic areas. So, I think we're pushing towards that granular analysis and really need to see how it pans out, so we're heading in the right direction there.

MS. SHENG: Thanks. Any other questions?

CHAIR WEISENMILLER: The same question on the geographical distribution. So, to the extent you and staff can communicate on the PV rollout, where it is by area, and make sure we're synced up there would be good. And, certainly, similarly on demand response. That as we get more into the geographic effects, the spatial effects trying to make sure our forecasts for the preferred sort of lines up pretty well.

MS. SHENG: Sure. Definitely, when we look at the PV adoption, for example, definitely we see more pick up in the inland areas, you know, territory compared to coastal areas. And, you know, those are the additional information we can work with CEC to gain a better understanding of.

As to DR, I think that's an evolving area as, you know, CPUC working on the DR verification. We're still working with a lot other stakeholders to determine what's the right DR programs for us to incorporate on the demand side and, you know, how do we account for those megawatts. So, I expect we would work together with CEC on those issues.

CHAIR WEISENMILLER: Great.

COMMISSIONER MC ALLISTER: Thank you.

CHAIR WEISENMILLER: I guess the last question is, historically, there were some issues on peak normalization. Are they done?

MS. SHENG: We are really pleased the last year, you know, we work with CEC on the issues and we have also brought industrial experts to look into what's the best practice in that area. And I would accomplish [sic], you know, CEC for making some process changes to revise their forecast.

And I think that's a pretty good evolving process and we would continue to support CEC for their updates in those areas.

MR. KAVALEC: We'll go through this exercise again for the 2015 loads, as I mentioned earlier. And each time, hopefully, we're getting closer and closer to a consensus in terms of method. But we're not quite there, yet.

CHAIR WEISENMILLER: Xeno's Paradox.

MR. KAVALEC: Pardon?

CHAIR WEISENMILLER: Xeno's Paradox.

COMMISSIONER MC ALLISTER: Hopefully, we can do that in a little more timely fashion and not have it crop up on us right at the very end, like it did two years ago.

MR. WENG-GUTIERREZ: All right, so now I will proceed with the San Diego Gas & Electric planning area. Again, it’s going to be very similar to the other two planning areas that I’ve already gone over.

So, in general, this actually had no -- this planning area had no definitional change. We didn’t make any additions or subtractions to the region. It stayed the same, so it actually lends itself to a better comparison between the update in 2014 and the new work.

In general, the mid-case is up slightly compared to the update in 2014, and this is primarily due to the faster growth in number of households that was mentioned earlier today, as well as a slightly higher EV forecast.

Sales are down slightly because of the higher PV adoption. And then the peak demand, of course, is even more significantly down because of the higher PV adoption.

So, here you actually are able to see the update in 2014, although the legend doesn’t mention it here. The red line, as is consistent with all the other slides that we have the update on, is representative of the 2014 update.

And as you can see, it's pretty close to the new mid-case. And in 2025, it's about 280 gigawatt hours. Our new update is about 280 gigawatt hours above the update in 2014.

So, just to take a quick look at the growth rate of the households across the forecast relative -- from the update to the new preliminary numbers. You can see that given that the update is basically in line with the low demand case, that almost nearly every case that we have for the new forecast, the preliminary forecast, we have households growing at a higher rate or we have a higher number of households and that lends itself to a higher set of demand numbers, as you'll see.

And Chris had mentioned some of the reasoning behind why the household growths are the way they are this IEPR cycle.

So, comparison of the sales numbers shows that the mid-case is growing. They're pretty close to each other, but our new mid-case is growing slightly slower than the update in 2014. Again, the update in 2014 shows the numbers in their mid-case starting at a slightly higher point and growing at a slightly faster pace than we did for our new preliminary set of numbers. But, generally, the rates are fairly close.

But the end result is that nearly all three of the cases in the new preliminary are lower than the mid-case last year.

Taking a look at peak demand, as I said at the outset, the peak demand is reduced significantly because of the regional PV adoption. All three of the cases are lower than the update, the mid-case update in 2014. And the mid-case, the new mid-case update is nearly 200 megawatts below what we had in the update in 2014 and 2025.

The PV energy is consistent and looks very similar to the other planning areas, as well. So, for 2014 we certainly had, you know, a trend line there that's reasonable. This time around because of, again, the updates to our methodology, the tariff rates and others we see a much higher increase in the PV energy associated with the planning area.

And again, the magnitude of the PV adoption impacts is not as high as you might imagine, again corresponding to the peak conversion factors that were realized for the preliminary forecast.

And so, in all three cases we have higher peak impacts, but they're just not as high as you might imagine. In the CED-2015 preliminary case they correspond to around 1,200 megawatts of capacity in 2026.

And then, this chart looks similar to the PG&E numbers for the EV energy consumption. The mid-cases are somewhat similar to one another. We end up in 2025 with a value higher for the mid-cases, but in the mid-term it's lower, accounting for the actual sales that we're seeing in the region.

And again, efficiency programs look slightly different here for SDG&E. We did the EM&V adjustments, again accounting for the study results, the recent EM&V study results for the 2012 to -- the 2010 to 2012 program evaluation study. Using that as an adjustment factor for the entire -- all the efficiency programs that have been incorporated until 2014 gives us the blue line. And then adding on top of that, the 2015 program savings gives us the green line.

So, again, what's included in the actual forecast is the blue line from 2010 to 2014 and the green line from 2015 to the end of the forecast.

So, as with the other utilities, the other planning areas, we did a comparison with the SDG&E's forecast. In general, SDG&E has a lower EV forecast than us, by 200 gigawatt hours in 2026. They also have a lower PV forecast by about 300 gigawatt hours.

Netting out those differences, our sales numbers are very close. And then, our peak forecast is also close in the 2026 time frame.

So, in general we felt like we understood the differences and we felt that it was -- you know, we'll take a look at those areas that are different and see if we can improved as we go forward developing a revised forecast. But, generally, we felt pretty comfortable with the general outcome.

And again -- nope. So, there are a couple of issues that we're going to take a look at. So, we're pleased that SDG&E is taking the approach is taking the approach of and end-use modeling approach. But there are a couple of things that we want to take a look at and, namely, lower residential sales in the different paths, and then the higher commercial sales for forecasts. And there's some differences in the commercial floor space estimates and we're going to probably take a closer look about that and have discussions with them about that as we go forward with the revised forecast.

And then there's also an issue with the historical street light sales numbers.

And that is, in fact, the last slide. So, I'll be happy to answer any questions you have.

COMMISSIONER MC ALLISTER: Has this street light issue come up in any other service territory?

MR. KAVALEC: Yeah, it pops up periodically for all the different planning areas. But recently we've had some issues with street lighting, how it's classified and delivered to us for San Diego and for LADWP.

COMMISSIONER MC ALLISTER: Does that have to do with the ownership of the lighting, whether it's utility-owned or city-owned, or whatever?

MR. KAVALEC: Yeah, I'd have to ask the utilities to speak to it, how they classify the street lighting.

We use a NAICS coding and I'm not sure exactly how they group their street lighting into that NAICS category.

COMMISSIONER MC ALLISTER: Thanks. Yeah, no new questions on this. Is SDG&E in the room here? Oh, great, there we go.

MR. WENG-GUTIERREZ: So, we'll invite San Diego Gas & Electric up to make comment.

MR. VONDER: Thank you, Malachi, good job. Commissioners, thank you for giving us the opportunity to comment. And I'm Tim Vonder, with SDG&E.

I'd like to begin by saying that we concur with staff's analysis of the two forecasts and the differences between them. I'd just like to talk about it a little.

If you were to just take a look at total energy sales, you know, our differences by the time we get to 2026 is less than one percent.

Like Malachi pointed out, with regard to PV and EV, staff is higher in both cases. We want to investigate that and understand that a little better. But with them being higher, about in the same magnitude that the two net each other out, and brings us back to being pretty close together.

If we weren't to consider -- if we were to take PV and EV, and set them aside, and compare our forecasts again, we're less than one percent difference for the remainder of the forecast.

There are a couple of things that Malachi mentioned at the very end, where there are issues that we need to look into. One of the issues has to do with us going back to a end-use modeling technology. And we're just kind of getting off the ground on that right now. And we made an error when we initialized our model in the residential area, because our forecast from 2014, it dips down in 2015 and it recovers.

And we've been looking into that and we think the reason is the way we initialized our model with standards and the compliance rate. We assumed 100 percent compliance right off the bat. And, usually, modeling custom is that you kind of bring them in little by little. And if we straighten that out, that's probably worth about 145 gigawatt hours right there in 2015. When we straighten that out, I think we're going to take care of that difference.

And then one other little difference that we noticed with staff, and this was across the board with all planning areas, is that we started with 2014 actuals. And 2014 is still a forecast year for staff.

Now, when staff updates their forecast in the revision process, they'll be using that. And they also indicated that they will be using the 2015 peak data when summer comes along, and we get that.

We'd like to correct our forecast for our residential error and we'd like to also kind of update our forecast. Whether we submit these forms or not, we want to update our forecast a little. So that when the revision process is complete we will have an updated forecast to compare to your updated forecast.

And we really do look forward to working with staff between now and then, especially to understand our differences in PV, EV and see if we can get a little closer. But it's been a pretty pleasurable experience working with staff so far and we're satisfied at this point.

COMMISSIONER MC ALLISTER: Great, thanks. So, could you describe a little bit, not the error or anything. I'm not so interested in that, per se. But your sort of reasons, really, the implementation of a more bottom-up model?

MR. VONDER: Our implementation of an end-use model?

COMMISSIONER MC ALLISTER: Sorry, the end-use model, yeah.

MR. VONDER: We're going with a model that Itron had developed, called the SAE model, Statistically Adjusted End-Use Forecasting.

We used to forecast -- many, many years ago we had the Commend Model and the REEPS model, and that was totally end-use. And then, we abandoned that, along with the other utilities, many years ago. And we went to strictly econometric. And now, we're starting to come back to end-use modeling. It will never get all the way back to REEPS and Commend but, you know, we're working on that.

So, we've been working with Itron to help us initialize the SAE Model in both commercial and residential. We're working on it. We had to work pretty hard to get a forecast out in time to file. And

I think some things got overlooked. But we're definitely working on it.

And I will say that there is one thing that we desperately need, and that is a new CEUS Study.

COMMISSIONER MC ALLISTER: Yes, I knew you were going to say that. I was about to ask. So, we're working on that really hard, too. Staff is sweating that at least as much as you're sweating your model.

MR. VONDER: Okay.

COMMISSIONER MC ALLISTER: So, we're totally agreed. I guess, you know, creative thinking about how we can gather data to inform that or how, sort of, you know, a partnership might help. I mean, I'm really enthusiastic about a move back to a Back-to-the-Future kind of thing in terms of getting a handle on realities on the ground, and then having them reflected in the modeling. A lot of work, but we have a lot of technology at our disposal, as well. And so, certainly interested in how that effort goes.

And one question. How geographically disaggregated are you doing this?

MR. VONDER: Well, right now it's at the county level, at our service territory level. But we just filed a DRP filing with the Public Utilities Commission and we're getting ready to start forecasting at a more detailed level. If we don't produce a forecast at a more detailed level, we want to get much better at distributing our system level forecast at a much more granular level.

So, the DRP was our first try, you know, at this and I think it's kind of a learning exercise for everybody that participated in it. And I think in the future we'll be able to do that. I sure hope we will.

COMMISSIONER MC ALLISTER: Yeah, me, too. And I think this would help our staff, I mean if we can sort of figure out how to talk the same language, and at the same level of aggregation, then I think it would really help our process and potentially improve our methodology, and be just a good thing all around.

MR. VONDER: With all the questions being asked lately, end-use modeling is necessary.

COMMISSIONER MC ALLISTER: Yeah, great.

MR. VONDER: I'd like to make one other comment because there was a question about lighting. There is a difference in our lighting forecast, but that difference really is in how we treat traffic lights. We classify them according to a commercial rate, not a NAICS code. And the commercial lighting is pushed up into our commercial category.

So, we didn't leave it out. It's in there, it's just not in the lighting category that you're used to seeing. So, it's there.

COMMISSIONER MC ALLISTER: Okay, thanks for that.

MR. VONDER: It's just not visible.

COMMISSIONER MC ALLISTER: Okay, thank you.

MR. WENG-GUTIERREZ: All right, great. So, I'm going to hand it over to Cary Garcia.

MR. GARCIA: Hi, I'm Cary Garcia. I'll be presenting our POU forecasts. We'll start off with LADWP and then we'll finish up quickly with SMUD.

At the end of each presentation, I'll give some time for LA I think Yaman is on the line. I'm not sure about SMUD, I think they'll be providing written comments.

So, first, we have a quick summary of the forecast for LA Electricity consumption is a little higher in this forecast compared to the 2014 updated, and this the result of an increase in the number of households.

Sales are down due to higher PV in this forecast. And as Asish mentioned, we have some rate escalation leading to that.

Similarly, the peak forecast is below 2014 and this the result of higher PV in VACS.

Then we have our electricity consumption for LA The two mid-cases are pretty close in comparison, but 2014 is slightly higher. By 2025, our mid-case, now, will be at about 27,300 gigawatt hours.

And as I just said in that quick summary, the higher number of households is what's leading to this slight increase.

Now, we're at the projects for the number of households. Growth here is comparing 2013 through 2025. Our new mid-case is a little higher than then the 2014 update. Although small, this is what pushed up that consumption.

Here we have electricity sales for LA The new mid-case is about 24,835 gigawatt hours. Compared to consumption, this mid-case is below the 2014. And this is due to that increase in PV. You can see a slightly flattening out of the mid-case sales near the end of the forecast period.

Now, we have our peak demand for LA A faster early growth here in comparison to the 2014 update. By 2025, we're about at 6,276 megawatts, which is about 75 megawatts below the 2014 update.

Now, we have PV energy. The low, mid and the high all exceed the 2014 update. By 2025, the new projections for PV energy is about 1,000 gigawatt hours.

Annual growth here, if you want to compare that, from 2014 to 2025, in the 2014 update, was about four and a half percent.

If you look at the new, 2015 mid-case, we're growing at about 14 and a half percent, annually.

Here we have PV impacts for LA A similar story to energy, growing at very similar rates. The mid-case here is about 100 -- sorry, the mid-case here is about 250 megawatts, which is about 180 megawatts more than the 2014 update in 2025.

Now, we have our light duty EV energy, which we've seen before in several of the slides. Very similar story here. There's an adjustment in that near period for the actual EV adoption.

The mid-case, in this case, is just an average of our high and our low, a rough average of the high and the low.

If you want to look at 2025, the new mid-case is about 50 gigawatt hours lower than the 2014 update.

Once again, we have our efficiency program impacts. Slightly different than with the IOUs. Here, we have not included 2015 impacts, yet, because we don't have access to that data. So, we start off from 2010 to 2014.

We can begin with the red line, which has no

EM&V adjustments. The blue line has our EM&V adjustments. And then we can move on to the green line, which includes the 2014 efficiency programs. And so, the net effect is about 145 gigawatt hours and that decays a little bit until 2026, and leaves us with about 40 gigawatt hours left.

Here we have electricity consumption by the climate zone for LA You can see here the inland area, in all three cases is a little higher. What we're seeing here is a little bit more inland growth in households, as well as the commercial sector.

Now, we look at growth in peak demand by climate zone and we see it's a little bit less of a distinction between the two zones. Although, there may be a little bit more inland PV driving -- well, this might be the result of more inland PV driving down that growth.

Here we have a comparison with LADWP's forecast. LADWP has higher EV forecast, but a lower PV forecast by 2026. These are both pretty significant. If we net out these differences, our sales are a little higher in our 2015 preliminary case. The difference here is about less than one percent, though.

On the other hand, our peak forecast difference is a little larger when comparing our 2026 numbers. If we net out these PV differences, our forecast is around

280 megawatts higher by 2026.

Here are some issues we want to work with or we have been working with LA on. One of the issues is with our weather normalized peak that we use. I believe LA is using the actual peak value right now.

Another issue that we've discovered with LA is that they have a new billing system they're still trying to work around. There's some new things that they still have to discover there.

Another issue that we've seen in some of the other presentations is an issue with the street lighting sales. Ours is relatively flat, whereas LA has a significant increase in their sales.

Another difference that we want to look at -- or another issue we want to look at is the difference in sectors. We've been encouraging LA to adopt similar sectors as the Energy Commission's demand forecast, and this will just allow comparisons in the future to be much easier.

I think that's my last slide. And I think Yaman is on the line, I hope.

MR. NANNE: Yes, good afternoon. Can you hear me?

MR. GARCIA: Yes.

MR. NANNE: Okay, yes. I just want to say thank you, Cary and Chris, for the analysis you've done and keeping us posted along the process.

So, I just wanted to comment on a couple of items in regards to the differences we're seeing. As you mentioned, you're seeing a higher PV forecast. And for us, what we're looking at right now is in our integrated resource plan we're saying that we're -- as of now, we are going to abide by the ability to limit our net metering at the five percent penetration level. So, we're actually capping, at this point in time, net metered PV penetration at 310 megawatts. And I think you guys go a lot higher than that.

That's, of course, needless to say, once we get there, I don't know how it would be an argument for us to say that for people that you can't, you know, get net metering credits for their solar.

So, we're going to be looking at that, obviously, as this -- as well as the CPUC is looking at that.

In terms of peak demand, I did a preliminary analysis and we're seeing, we're starting to see a shift in when our peaks are happening. Typically, historically, 1995 to 2000 they were happening in August and June. We're seeing more of a September peak, lately, and more of a needle peak. So, we're going to be looking into trying some new models that possibly include quantifying with rations to see if there’s any way we can pick up on that more often. And then also, maybe possibly going towards a more weather normalized peak demand model.

In terms of EV forecast, one thing is why maybe we’re seeing higher than you are is we’re looking at not just -- we don’t have all of our EV customers on dedicated meters. So, we’re basing it off of data that we’ve received from our rebate program, as well as the data that we were able to gather from California Sustainable Energy Center.

So, we believe that there’s a lot more EVs out there than we’re actually metering at this point. But moving forward, what our rates group has done is they’ve now made it a rule that if you want to get the EV discount that you have to go with the dedicated meters. So, hopefully, that will help us get a more accurate reading of EV adoption moving forward.

And in regards to the definition of classes, as Cary mentioned we did have a new billing system, a customer information and billing system that went online at the end of 2013. So, we’re still kind of working through some of the bugs in that and trying to, you know, potentially reclassify. We’ll redefine the classifications that we're using for forecasting. And what we're also going to be working on is trying to fix some of the NAICS codes that are assigned to those customers.

So, for street lighting, similar to what San Diego Gas & Electric mentioned, what we do is we do have a Bureau of Street Lighting that, you know, owns and operates all the street lighting. And then, you know, we charge them for that. But we also have what we call an outdoor area lighting rates. So, some of that is grouped into the street lighting, as well, and then some of it falls into commercial. So, we're also going to work on trying to clean that up, as well, moving forward.

So, that's my comments on the comparison. And we'll continue, you know, to coordinate further.

MR. GARCIA: All right, thank you, Yaman.

MR. NANNE: Thank you.

MR. GARCIA: Do we have any questions?

COMMISSIONER MC ALLISTER: Maybe we can ask the POU, is the only other -- just SMUD is the other POU or do you have others?

MR. GARCIA: Yeah.

COMMISSIONER MC ALLISTER: Okay, great. So, let's ask the DWP representative to stick around and maybe we'll ask them both some questions. Thanks.

MR. GARCIA: All right, I'll move on to SMUD. All right, so here we have another quick forecast summary. Like LA, we have a higher household forecast here, resulting in higher consumption. But this has been offset by the growth in -- oh, offset by lower EV growth.

PV adoption is less here, compared to the IOUs, and this is leading to faster growth in terms of sales and peak.

As Chris mentioned earlier in the day, SMUD is no longer a planning area, but is a climate zone within a planning area. And this will be in the Northern California non-CAISO planning area.

As far as being a climate zone in that planning area, the consumption for them was much slower, but their peak demand -- oh, sorry. Their consumption was growing faster, but their peak demand was growing slower.

So, here we have electricity consumption for SMUD. In particular, Northern California experienced a lot of -- or were expecting a lot of household growth in Northern California. So, the new mid-case puts us around 326 megawatts above our old case from 2014.

Here's our growth in number of households. Our new mid-case is growing fairly significantly higher than our 2014 update. By 2015, we're at about 600,000 households, in comparison to 2014 mid-case that had us at 575,000 in 2025.

Here we have electricity sales for SMUD. More PV here results in our sales forecasts being closer to last year's estimates. And that's about 200 gigawatt hours more than 2014. And this is due to slightly more PV growth.

Here we have peak demand for SMUD. More growth compared to 2014. By 2025, our new peak forecast will give us about 3,400 megawatts of peak demand.

Now, we have PV energy. This increase is about 100 gigawatts for the new mid-case. We had growth in the commercial sector, leading to higher commercial PV adoption.

Now, we have PV as peak impacts. On the opposite side of our 2014 update and this was largely due to that shift in the peak factor, which in SMUD's case was significant.

And so the difference here between -- in 2025, when we compare our 2014 update to the new forecast, is about 60 megawatts. Oh, I'm sorry, that's a little too much there.

So, now we have our light duty EV forecast. The new mid-case is growing around 36 percent, compared to the 39 percent from our old mid-case. So, that's a slight reduction. And this is very similar to the previous slides we saw as far as the EV growth goes for the different planning areas.

Now, once again, we have our efficiency program forecast, our efficiency program impacts. We'll start off, again, with the red line, showing our cumulative savings from 2010 to 2013, with no EM&V adjustments.

The blue line representing our cumulative savings, including those EM&V adjustments.

And then the green line, now representing the addition of 2014 program impacts.

So, by 2026, we still have -- we have a little more than we have in 2014. In fact, about 42 gigawatt hours.

Now, as mentioned earlier, SMUD is now a climate zone within a planning area, that Northern California Non-CAISO planning area. So, here we see SMUD electricity consumption growing at a much or fairly higher rate compared to the Turlock Irrigation District, and the Balancing of Northern California, not including SMUD.

Now, we have our peak demand for these climate zones. Well, for SMUD. Relative to the other areas, there's still more PV growth in SMUD's territory, and so that's kind of putting them down below the other two areas as far as peak demand growth.

Okay, now, for our comparison with SMUD, SMUD has a higher EV forecast by about 50 gigawatt hours in 2026, but they have a lower PV forecast in comparison to ours that's significantly high, by about 300 gigawatt hours in 2026.

If we net out these differences, our sales in 2026 are significantly lower than our 2015 mid-case, and that's about 800 gigawatt hours. This difference is largely due to differences in our residential forecasts.

The peak forecast is much closer. If we net out our PV differences, we're within about three percent of each other.

These are just a couple of issues that we want to review with SMUD. One is the PV adoption that we want to get a handle on, and see if we can get closer on aligning our forecasts.

And then, also, we want to work out some issues as far as the residential forecast comparisons. SMUD combines a short-term, as well as a long-term forecast, which makes comparisons difficult.

And then, as far as the Energy Commission goes, or the demand forecasting on our part, we need to look at miscellaneous plug loads and get a handle on that for the revised forecast.

So, I'll invite SMUD, if we have anybody? I don't think we do. So, I think they'll be sending in written comments. So, if there are any questions?

MR. KAVALEC: I believe Toyama (phonetic) is on vacation this week so --

MR. GARCIA: Oh. Yeah, so any comments or questions.

CHAIR WEISENMILLER: Yeah, so the first question is with LADWP and SMUD, when do they run into the net metering cap? There's been some legislation this year to adjust that for the POUs, or there was some for the POUs?

MR. GAUTAM: I think in the AB 327, it also calls for a move, just like the IOUs, for new contracts -- or a new NEM payment structure in 2017, or the five percent cap, whichever's earlier.

CHAIR WEISENMILLER: Okay.

COMMISSIONER MC ALLISTER: Is the rep from LADWP still on?

MR. NANNE: Yeah, sorry. Yeah, let me chime in on that. It's kind of -- so, we're looking at it in a way as an accommodation between what's coming from SB 1 and AB 327, right. So, SB 1 has a specific dollar and megawatt target. So, we're actually going to be exceeding the megawatt target of SB 1, staying with the dollar target in terms of rebates. But what we're looking at is saying we're going to adopt what AB 327 does, and allows us to limit net metering at five percent until we do further studies to determine, which are actually already underway, to determine how that can be integrated into the grid.

COMMISSIONER MC ALLISTER: So, what percentage does just getting through SB 1 get you to, in terms of the cap, in terms of the proximity to the cap?

MR. NANNE: Yeah, SB 1, I think our target's about 280, so almost gets us there.

COMMISSIONER MC ALLISTER: Interesting. So, you're concerned about the ability to incorporate five percent into your distribution network?

MR. NANNE: Right, yeah, so I don't want to get too much into the integrate resource plan. So, we're looking at it specifically from net metering. We actually have a lot more distributed solar coming online. We have, already existing, 115 megawatts of feed-in tariff that's already being developed. So, we're considering expanding that additional 300.

We also are planning a community solar program right now that could possibly be anywhere from 50 to 100 megawatts.

So, our concern is in terms of the operational control of that solar. So, we look at feed-in tariffs and community solar as we're able to control that because, you know, we require certain metering or either we own it, we own the control.

But whereas net metering, it's on the customer side and we don't necessarily have control of it unless it's, you know, we do that for larger size projects. So, that's how we're looking at it right now.

COMMISSIONER MC ALLISTER: So, are you looking at Smart inverters and sort of strategies to be able to control some of the NEM solar, or at least influence it and use it for, you know, ancillary services? Or are these just turn it down if need be, Smart inverters.

MR. NANNE: Yeah, I don't want to give you -- I'm not an expert on that. I can get back to you on that information. We do have a group that is looking into that. But I don't have the answer. We don't have any immediate plans to roll out, you know, Smart inverter incentives or anything like that.

COMMISSIONER MC ALLISTER: Okay.

MR. NANNE: But we do have a group looking into it. So, if you want, I can look into that and get back to you on that.

COMMISSIONER MC ALLISTER: That would be great.

MR. NANNE: Okay.

COMMISSIONER MC ALLISTER: I wanted to -- really, my main question was about the savings in 2014. It looks like you guys got a lot of efficiency savings in 2014 and I wonder if you can unpack that a little bit. I'm assuming those are unverified, but they look pretty big, regardless.

MR. NANNE: Yeah, I would have to get back to you on that. We did have our board adopt higher energy efficiency targets, yeah, starting in the beginning of 2014. Basically, the goal was to get 15 percent by 2020. So, that's where that adjustment comes from.

But if you want more specifics of what's going on in 2014, I'll also have to get back to you on that.

COMMISSIONER MC ALLISTER: That may be reflected, already, in the latest round of reports you guys sent us. But it would be good to get an update on that, so maybe --

MR. NANNE: Okay. Yeah, I'll get in touch with our energy efficiency group and see what their actuals have come in for 2014.

COMMISSIONER MC ALLISTER: Great. So, the other question I had is kind of just one of, you know, POUs and IOUs, apples-to-apples with regard to the fact that

DWP, certainly, and SMUD I think also does either an IRP or something akin to IRP that includes a lot of the stuff that we break out for the IOUs, in terms of AAEE and all that. Right, is that a fair statement, Chris?

So, how does that affect the presentations that we've seen here today? Has the AAEE equivalent been stripped out of the POUs for this base forecast, or sort of what are we looking at one relative to the other, in terms of POUs and IOUs?

MR. KAVALEC: Yeah, we tried to make that comparison as close as possible for POUs and IOUs. So, for efficiency, it's only including the committed efficiency, so nothing beyond 2014.

COMMISSIONER MC ALLISTER: And you -- the utilities can provide -- like the POUs, DWP and SMUD can provide you with that information or do you have to kind of model it away?

MR. KAVALEC: No, they -- we have information from two sources, at least, the AB 2021 reports, as well as the demand forms they file with us. They include future efficiency beyond the current programs.

COMMISSIONER MC ALLISTER: Okay.

MR. KAVALEC: So, that's what we're going to rely on, and as well as other discussions with the POUs to develop AAEE for the POUs.

COMMISSIONER MC ALLISTER: Okay, so that discussion for the POUs' purposes, or for our purposes with respect to the POUs is all about essentially whether we -- so, our vetting their predictions of future efficiency and seeing if we agree, and modeling them.

MR. KAVALEC: That's right.

COMMISSIONER MC ALLISTER: Okay. Okay, well, that makes sense.

Yeah, any other questions?

CHAIR WEISENMILLER: No, I think I'd encourage staff in LA to talk about the port issues in terms of load at the port and/or electrification.

COMMISSIONER MC ALLISTER: Can DWP talk about the ports and what's going on there? Oh, it seems like we lost him, okay. Oh, there he is.

MR. NANNE: Yeah, I can make a slight comment on that. But I'd also have to get back to you in more detail. There is a reduction in port electrification from LAX. However, that's an agency, you know, that's in charge of that. So, I'd have to get back to you on the details of that.

But our forecast, our next forecast is going to reflect lower port electrification.

COMMISSIONER MC ALLISTER: Right, okay.

MR. KAVALEC: And, Yaman, your forecast currently includes some assumptions about electrification in San Pedro?

MR. NANNE: Yes, that’s correct.

COMMISSIONER MC ALLISTER: Okay.

MR. NANNE: Yeah, but again, that’s -- we have received word that that’s being reduced, so we’re going to reflect that in the next forecast.

COMMISSIONER MC ALLISTER: Great. Okay, thanks. Anybody else? No. The PUC Commissioner doesn’t want to ask the POUs anything?

(Laughter)

CPUC COMMISSIONER FLORES: Stir up trouble.

COMMISSIONER MC ALLISTER: Thank you, Cary.

All right, we’re to public comment. I only have one blue card, so maybe we’ll just open it up, in case anybody didn’t fill one out, later.

But our sole speaker this afternoon, Jeremy Waen, from Marin Clean Energy.

MR. WAEN: Hi there, Jeremy Waen with Marin Clean Energy. I’m here to talk about a type of load-serving entity that hasn’t got much discussion here today, but is part of the IEPR process. That is our community choice aggregations.

I work for one of three active CCAs in the State of California. And with this IEPR cycle, it's actually a significant milestone for us because it's the very first time that we are reporting directly to the CEC to have our load and supply reflected within the IEPR process.

We've been serving customers since 2010, but our peak demand has grown enough so that we've crossed that 200-megawatt threshold to start reporting to the IEPR.

Similarly, Sonoma Clean Power, which is the second of three CCAs, also serves a large enough load at this point to be reporting into the IEPR process.

And the third CCA is the City of Lancaster, in Southern California Edison's territory.

We are reporting in and we're very interested in the accuracy of the IEPR process because it ultimately informs the procurement planning processes that happen at the CECD and inform the bundled procurement practice of the utilities.

This has a fundamental impact of -- it has a direct material impact on the abilities of CCAs to compete against investor-owned utilities on price. Because so far as the utilities procure too much power, or procure power on behalf of the customers that we serve, our customers end up paying that cost anyhow.

So, we want to make sure that our load

information is accurately reflected within the IEPR process so that it can be accurately acted upon at the CPUC level for their planning processes.

We also believe that there are, there will be CCAs that will not reach that 200-megawatt threshold to directly report into the IEPR process. And we believe that there should be some aggregation factor to account for the smaller CCAs when they form over the coming years.

And also on that note, CCAs are popping up more and more, and in more numbers. And the existing CCAs are continuing to grow. And we believe that there does need to be some tracking of the load served within the utilities' territories of whether they're being served by bundled or unbundled service, and whether that load net shift is growing. Where there are trends and how much is being served by unbundled or bundled.

And lastly, to the extent that we are bringing on distributed energy resources, we ask that that information be incorporated into the assumptions that go into the IEPR process, as well. We don't want all the distributed energy resources that we bring online to somehow drop off the radar and not be reflected in the IEPR.

COMMISSIONER MC ALLISTER: Thanks very much for being here. I guess I have a question, you know, so a kilowatt hour that goes to one of your customers, and you procure and sell, is that being reported in the data that PG&E submits?

MR. KAVALEC: Yeah, so in our sales forecast, our disaggregated version that we use for renewables analysis and so on, we report PG&E bundled -- or IOU bundled, unbundled, and CCA.

COMMISSIONER MC ALLISTER: Okay.

MR. KAVALEC: So, PG&E does report that, but we also get data from some of the CCAs and we try and reconcile the data, and develop projections for the CCAs.

And right now we're including Sonoma, Marin and Lancaster, down south.

COMMISSIONER MC ALLISTER: Does that, does the data that comes from the utility and the CCA, do those data match up pretty well?

MR. KAVALEC: They're usually pretty close. But I think this is a conversation -- as CCAs become more widespread, this is a conversation we're going to have to have with the IOUs, as well, to fully reconcile their expectations with ours and the CCAs.

COMMISSIONER MC ALLISTER: What sorts of DG are bringing on, distributed energy resources are you bringing online? Is it net metering your customers, or is it more community choice, or what?

MR. WAEN: We have rooftop solar and net energy metering that we have a very high participation rate within our service territories. We also have an obligation through the legislative mandate and CPUC to procure energy storage for the customers we have. And we are beginning to bring some of that online, both at the commercial level and also the residential level.

We also have a demand response pilot that we ultimately aspire to bid into the ISO market, as a supply resource. So, that's another type of resource that will need to be tracked.

We also have, at least MCE's territory, a particularly high adoption rate of electric vehicles, and that there are certainly aspirations to increase further the adoption and usage of electric vehicles. So, definitely think all of those types of technologies are being acquired by our customers, and facilitated in a way by the programs and pilots that we're offering to our customers, as well.

COMMISSIONER MC ALLISTER: Yeah. I mean, it's very exciting and I commend you guys on all the programs you've got going.

I want to avoid, you know, having essentially double counting or not counting. And so, like if the PG&E truck comes to do an interconnection on a PV system, and that Smart meter is PG&E's meter, right, on one of your customers. So, does that data come up through the interconnection data on PV that PG&E's going to support to you, going to report to us here, for forecasting purposes? Or, are we needing Marin Clean Energy to submit that, the fact that that system exists?

MR. GAUTAM: In this IEPR, I don't recall getting any interconnection data from CCA. So, it might be a conversation we need to have.

COMMISSIONER MC ALLISTER: It would be good to make sure that the information about that system and its location is coming in from somewhere, right?

MR. GAUTAM: Yeah.

MR. WAEN: Absolutely. This is, as I mentioned, this is the first time reporting into the process, so we're still even learning which forms we should be looking out for.

COMMISSIONER MC ALLISTER: Thank you for that.

MR. WAEN: The one other thing that I meant to mention is we also administer an energy efficiency program under the CPUC's authority. And so, there are energy savings there, too, that should ultimately get rolled into this.

COMMISSIONER MC ALLISTER: So, I'm wondering, Commissioner Florio, does sort of the reporting -- I know you're not the lead on efficiency. But I'm wondering about the -- how the CCAs are sort of treated and their expectations of reporting to the PUC, and whether that kind of translates to -- you know, maps over to our forecasting efforts?

CPUC COMMISSIONER FLORES: My understanding is that, at least for Marin, there's separate reporting and accounting for the programs that they administer.

COMMISSIONER MC ALLISTER: Yeah.

MR. WAEN: That's my understanding, too.

CHAIR WEISENMILLER: Although, again, I guess what don't know, stepping back and looking at the Governor's Executive Order, and certainly legislation, how the CCAs fit in that context where, in many respects, we're talking about stepping up energy efficiency, certainly stepping up electrification of transportation systems, stepping up renewables, with a real greenhouse gas focus there, perhaps in some sort of IRP process. How do you play across those three buckets, vis-à-vis, you know, the PUC?

MR. WAEN: So, we straddle an interesting line as far as jurisdiction goes. There's certain areas where the CPUC has direct jurisdiction over us, as far as compliance with the Renewable Portfolio Standard, the energy storage obligations that I was mentioning, the resource adequacy requirements. And then, things like energy efficiency to the extent that we are leveraging ratepayer funds to fund the energy efficiency. Those are all CPUC jurisdiction.

For our general procurement and all of our other services that we provide to our customers, it’s all within the jurisdiction of our governing board. So, we certainly view ourselves as one of the many pathways towards meeting the Governor’s goals for further EE adoption, EV deployment, GHG reductions overall. But we -- it’s an interesting fit of how we layer in with the different jurisdictions and the different authorities that are there.

CHAIR WEISENMILLER: Let’s say on charging infrastructure for transportation, would you anticipate doing that or would you anticipate, say, PG&E putting in charging infrastructure in your area?

MR. WAEN: We have helped to fund some deployment of EV charging within our service territory and we are interested in continuing to do that.

I don’t want to risk any kind of ex parte notice by violation with Commissioner Florio, but there are proceedings ongoing at the Commission, exploring further deployment of EV charging infrastructure. And CCAs could play a role in that.

CHAIR WEISENMILLER: Yeah, I was trying to understand whether -- you mentioned how you were in a hybrid situation, where in some areas you have PUC regulation, others local control. And I was just trying to understand some of the boundaries there, you know, particularly on like charging infrastructure?

MR. WAEN: There, too, if it were to leverage ratepayer money, the same way the energy efficiency programs leverage ratepayer money, then we would likely be beholden to the CPUC.

CHAIR WEISENMILLER: Okay.

MR. WAEN: Otherwise, it’s simply left to our means and our local jurisdiction to fund and plan where the charging infrastructure may be deployed.

CHAIR WEISENMILLER: Okay.

MR. KAVALEC: And I may have already asked you this once before when we talked, but are you guys now doing regular, ten-year forecasts for sales and for peak? And if so, how often?

MR. WAEN: We have an Integrated Resource Plan that we update on an annual basis, that is our analogous process to, say, the Long-Term Procurement Plan that the utilities undergo at the IOU level.

It's a document that we, our staff and our board create, and we vet through public review, and work with the consultants on. And we do conduct procurement over medium to long term. We have contracts that are up to 20 years in length. So, we are very much procuring on a longer term. And that document is a public document. I believe it's updated every, I want to say, third or fourth quarter of the year. And we're happy to keep providing that to the CEC to update the accuracy of the information in the IEPR.

COMMISSIONER MC ALLISTER: Okay, thanks very much for being here, really appreciate it.

MR. WAEN: Thank you, all.

COMMISSIONER MC ALLISTER: And it looks like Melanie might have an answer to our net metering system question.

MS. MC CUTCHEON: Good afternoon. My name is Melanie McCutcheon. I'm with PG&E and I did want to provide some clarification to Commissioner McAllister's question regarding double counting on our -- some of our demand side energy resources forecasts.

I can't speak for the energy efficiency side of things. But for distributed generation, we do include interconnections in Marin Clean Energy's area, as well as customers, as well as for other CCAs. So, we'll definitely work closely with CEC staff and Marin Clean Energy, and others, to make sure we're not double counting any DERs.

COMMISSIONER MC ALLISTER: Great. Thanks very much.

Okay, any other comments in the room? It looks like not.

And do we have anybody on the WebEx or phone?

MS. RAITT: No, but we can open up the phone line. So, if folks are on the phone, please mute your phone, unless you'd like to make a comment.

It doesn't sound like it.

COMMISSIONER MC ALLISTER: All right. Well, I want to thank staff on a job well done. The preliminary forecast I think is really solid work. And there are number of things to sort of think about further, and polish up as we move on in the year. Obviously, waiting for the 2015 data to come through so we can get it all tied up nice in a bow before the end of the year. Or, I guess, actually, early next year, probably. I see Malachi grimacing.

But I think this is really great work and thanks to Chris and the team, Asish, and Cary, and Malachi, and Chris for all the work.

And let's see, I guess I don't really have any other comments. Chair Weisenmiller, do you want to --

CHAIR WEISENMILLER: Well, again, I'd like to thank everyone for being here. Certainly thank the staff for their hard work in this area. I think this is one where it's been one of the Energy Commission's core covenants for years. And certainly appreciate the dedication to their efforts there and the feedback on how to make it better.

And I also want to thank Commissioner Florio for being here today and helping us dive into these issues.

CPUC COMMISSIONER FLORES: And we'll follow up back home to make sure we're coordinating to the maximum extent possible.

COMMISSIONER MC ALLISTER: All right. Thanks, Heather and the IEPR team, and all of you for sticking it out to the bitter end here. It's almost three o'clock, so we're adjourned.

(Thereupon, the Workshop was adjourned at 2:55 p.m.)

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